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4.3 POWER OSCILLATIONS

Learning Objectives

1. List the primary safety concern regarding unstable power oscillation.
2. List the major factors that can contribute to instability.
3. Explain the mechanism present at most BWR plants to guard against neutron flux oscillations.
4. Define the following terms:
   a. fuel time constant
   b. decay ratio
5. Explain why it is difficult to detect power oscillations.

4.3.1 Introduction

Boiling water reactors (BWRs) have complex dynamic responses that can result in the initiation of power oscillations. Of the various types of oscillations, those generated from control systems response are the most common. Controllers, such as the master recirculation flow controller, are typically more stable at the high end of their control band than at the low end. To account for this problem, interlocks and procedures prevent automatic master flow control below some value (typically less than 45%). Other control systems that effect BWR oscillations are the pressure control system and the feedwater control system. Even with the constant modulation of the turbine control valves to regulate reactor pressure and feedwater pump steam supply valves or feedwater regulating valves to control feedwater flow, a sinusoidal oscillation can be observed in reactor power during steady state operation. These oscillations are usually slow and small in magnitude. Figure 4.3-1 was taken from an operating recorder in a BWR control room and illustrates the power oscillations that occur at many plants during normal power operation. The amplitude of these observed oscillations has ranged from a few percent to fifteen percent. Oscillations that occur from control system responses are not normally divergent and do not challenge fuel safety limits.

Unstable power oscillations can occur during power operations or in conjunction with an Anticipated Transient Without Scram (ATWS). The primary safety concern regarding unstable power oscillations during normal operations is the ability of the reactor protection system to detect and suppress oscillations before they can challenge the fuel safety limits (Minimum Critical Power Ratio).

The type of instability that can lead to divergent oscillations and challenge fuel safety limits is a thermal-hydraulic, neutronic generated, density-wave instability that occurs inside fuel bundles. GE BWR plant and fuel design provide stable operation with margin within the normal operating domain. However, at the high power/low flow corner of the power/flow operating map, the possibility of power oscillations exists. The major factors that can contribute to instability are void fraction, fuel time constant, power level, power shape, feedwater temperature and core flow. To provide assurance that the oscillations are detected and suppressed, technical specifications require that APRM and LPRM flux levels be monitored when in the region of possible power oscillation. This requirement is based on the results of stability tests at operating BWRs. A conservative decay ratio of 0.6 was chosen as the basis for determining the generic region for monitoring for power oscillation. Decay ratio in this context is the measured stability of an oscillating system and is the quotient of the amplitude of one peak in an oscillation divided by the amplitude of the peak immediately preceding it. The amplitude is measured relative to the average amplitude of the signal. A stable system is characterized by a decay ratio of less than 1.0. As a result of recent power oscillation events, and a desire to minimize the possibility of exceeding the minimum critical power ratio (MCPR) limit, the BWR Owners Group (BWROG) and the NRC have agreed in principle to three plausible options that are discussed in Section 4.3.3 on Mitigation of Power Instability.

Thermal-hydraulic-neutronic instabilities in BWRs have been known to exist since the early days of BWR research using prototype reactors. Although this instability mechanism was identified early, the analysis methods needed to predict its effect are only now becoming available. Appendix 1, Analysis Methods Used For BWR Stability Calculations, is, therefore, provided for additional information.

4.3.2 Discussion of Power Instability

The basic mechanism causing flow and power instabilities in BWRs is the density wave. The effect of a density wave is illustrated in Figure 4.3-2. Coolant flows in the upward direction through the core and is guided by the channels that surround the matrix of fuel rods. Local voiding within a fuel bundle may be increased either by an increase in the power at a constant inlet flow, by a decrease in the inlet flow at constant power, or by an increase in feedwater temperature. This resulting localized concentration of voids will travel upward, forming a propagating density wave which produces a change in the localized pressure drop at each axial location as it travels upward. The effective time for the voids to move upward through the core is referred to as the density wave propagation time. In two-phase flow regimes, the localized pressure drop is very sensitive to the local void fraction, becoming very large at the outlet of the bundle where the void fraction is normally the greatest. Because of this a significant part of the pressure drop is delayed in time relative to the original flow perturbation.

If a sine wave perturbation of the inlet flow is used to illustrate this, Figure 4.3-3 is obtained. The localized axial pressure drops are also sinusoidal within the linear range; however, they are delayed in time with respect to the initial perturbation, the sine wave in this case. The total pressure drop across the bundle is the sum of the localized pressure drops. If the bundle outlet pressure drop (the most delayed with respect to the initial perturbation) is larger than the inlet pressure drop, then the total bundle pressure drop may be delayed by as much as 180 degrees with respect to the inlet flow perturbation and be of the opposite sign. This is the case in Figure 4.3-3, where an increase in inlet flow results in a decrease in the total bundle pressure drop. Bundle flow with this density wave propagation time behaves as if it has a "negative" friction loss term. This causes the bundle flow to be unstable, inlet flow perturbations to reinforce themselves (positive feedback), and oscillations grow at the same unstable frequency. Bundle flow instability starts when the outlet (i.e., delayed) localized pressure drop equals the pressure drop at the inlet for a particular density wave propagation time.

Power generation is a function of the reactivity feedback and, depends strongly on the core average void fraction. When a void fraction oscillation is established in a BWR, power oscillates according to the neutronic feedback and the core dynamics. Most important to this discussion are the void fraction response to changes in heat flux, including the inlet flow feedback via the recirculation loop, and the reactivity feedback dynamics.

One important difference between the neutronic feedback dynamics and the flow feedback dynamics is the fuel time constant. Before the power generated in the fuel can effect the moderator density, it must change the fuel temperature and transfer heat to the coolant. The fuel in BWRs responds relatively slowly with a time constant between 6 and 10 seconds. The delay times for unstable density wave oscillation and void reactivity feedback are not the same. Differences in the delay times add additional phase delays and can cause the void feedback to reenforce the density wave oscillations (effectively positive feedback). Decreasing the time response of the fuel generally has a destabilizing effect. Smaller response times can be a problem even if only a small portion of the fuel has the decreased time response, as was the case in the WNP2 event, because the most unstable bundles dominate the response.

When conditions within a reactor are such that it could become unstable (eg: high power and low flow), any perturbation in the inlet conditions can start the unstable oscillations. A moment before the instability event starts, the reactor is in a relatively steady condition with some particular power and flow. Initially the reactor will behave linearly and the oscillations will grow exponentially. As the oscillation becomes larger, the nonlinearities in the system begin to grow in importance. These nonlinearities have the effect of increasing the negative power feedback in the reactor. When a sufficiently large reactivity bias is reached an equilibrium is established, and a limit cycle oscillation remains. The amplitude of the resulting limit cycle oscillation will depend on various parameters and can be many times greater than rated full power.

BWRs can experience unstable power oscillation either in a single bundle (localized) or core wide. In the case of core wide oscillations, the entire core can oscillate together or part of the core can be increasing in power while another part is decreasing in power (out of phase). The out of phase oscillation is important because it is more difficult to detect. BWRs monitor local power at various radial and axial locations with the use of Local Power Range Monitors (LPRMs). The LPRMs consist of up to 172 stationary in-core detectors which are arranged in radially located assemblies of four detectors each, separated at axial intervals of three feet. The LPRMs in turn provide information to the Average Power Range Monitoring (APRM) System. In general for the majority of plants, a set of individual LPRMs provide information to a single APRM channel. APRMs sample power both radially and axially in the core and therefore, may not indicate the worst case out-of-phase oscillation since the oscillation may be masked by the cancellation between out of phase LPRMs that provide signals to the same APRM channel.

Bottom-peaked power shapes are more unstable because they tend to increase the axially averaged void fraction. This causes void perturbation to start at a lower axial level, and produces a longer delay time for the density wave which will be more unstable. Radial power shape is important because the most unstable bundles tend to dominate the overall response. Lower void velocities result in longer delay times for the density wave which will be more unstable. Increasing the subcooling of the feedwater inlet flow has two effects. First, it will tend to increase the operating power (a destabilizing effect) and second, it raises the boiling boundary (a stabilizing effect). In most cases the total effect is destabilizing. The fuel isotopic composition has an indirect effect on the density reactivity coefficient with the effect depending on the burnup. Generally increased burnup causes the density reactive coefficient to become less negative, which will tend to destabilize the core.

Many of these effects can accrue as a result of a single cause. As an example, fuel burnup will change the fuel isotopic composition as well as the axial power shape. Additionally, changes in other parameters can effect these factors. Increasing reactor pressure will decrease the core average void fraction and stabilize the reactor. Increasing the core inlet restriction (flow orificing) will increase the single phase component of the pressure drop across the core which retards dynamic increases in the flow rate (a stabilizing effect). Therefore, the effects of all parameters must be taken into account when evaluating mitigation strategies.

4.3.3 Mitigation of Power Instability

General Design Criteria (GDC) 10, 12, and 20 of 10 CFR 50, Appendix. A, require that protection systems be designed to assure that specified acceptable fuel design limits are not exceeded as a result of power oscillations that are caused by thermal-hydraulic instabilities. Minimum Critical Power Ratio (MCPR) is the primary fuel design limit that is being protected during potential instabilities.

The BWROG submitted to the U.S. Nuclear Regulatory Commission Topical Report NEDO31960, "Long-Term Stability Solutions Licensing Methodology," (Reference 7) for staff review. Long-term solutions described in this report consist of conceptual designs for automatic protection systems developed by the BWROG with its contractor, the General Electric Company. The automatic protection systems are designed to either prevent stability related neutron flux oscillations or detect and suppress them if they occur. This report also described methodologies that have been developed to establish set points and demonstrate the adequacy of the protection systems to prevent violation of Minimum Critical Power Ratio limits in compliance with 10CFR50, Appendix A, GDC 10 and 12.

Because of the variety of plant types, and the need to accommodate differing operational philosophies, and owner-specific concerns, several alternative solutions are being pursued. For some BWR/2s, existing systems and plant features already provide sufficient detection and suppression of reactor instabilities. This capability is limited primarily to those plants having quadrant average power range monitors (APRMs), it is referred to as Option II, and has been agreed upon by BWROG and the NRC. However, for most of the BWRs, new or modified plant systems may be necessary. A summary of the three most promising BWR owner group long-term solutions is provided below.

4.3.3.1 Solution Description Option I-A

Regional Exclusion, Option I-A, assures compliance with GDC-12 by preventing the occurrence of instability. This is accomplished by preventing entry into a power/flow region where instability might occur. An example of an exclusion region (I) is shown in Figure 4.3-4 along with the restricted (II) and monitored (III) regions. Upon entry into the exclusion region, an Automatic-Safety-Feature (ASF) function will cause the region to be exited. The ASF may be a full scram or a selected rod insert (SRI). For plants choosing SRI as their primary ASF, a full scram automatic backup must take place if the exclusion region is not exited within a reasonable period of time (a few seconds).

For plants choosing to implement this option (full scram or SRI), the existing flow-biased scram cards will be replaced. The new microprocessor-based cards will provide three independent functions: (1) a scram signal (that will be processed by the existing flow-biased scram system) if the exclusion region is entered, and (2) an alarm (directed to an existing alarm panel) if the restricted region is entered, and (3) automatic monitoring (using the period-based algorithm of solution III) within the monitored region to detect instabilities should they occur.

Entry into the monitored region is unrestricted. This region only defines a region outside which the monitoring algorithm is not active. The main purpose is to avoid false alarms from the automated monitor when operating at very low powers during startup. Intentional entry into the restricted region is only permitted if certain stability controls are in place. These stability controls deal primarily with power distributions and may be implemented by monitoring a parameter defined as the boiling boundary. The purpose of these controls is to assure that plant conditions that are sensitive to stability are bounded by the assumptions of the exclusion region boundary analysis.

4.3.3.2 Solution Description Option I-D

Regional Exclusion with Flow-Biased APRM Neutron Flux Scram, Option I-D, assures that BWRs with tight fuel inlet orificing (less than 2.43 inches) and an unfiltered, flow-biased scram comply with GDC-12 by providing an administrative boundary for normal operations in the vicinity of the region where instability could be expected to occur. During normal operation, the boundary of the exclusion region is administratively controlled, and operation within the region is to be avoided. If an unexpected operational event results in entry into the exclusion region, action to exit the region must be taken immediately. Oscillations that do occur in this situation should be automatically detected and eliminated by the flow-biased APRM neutron flux scram. This scram is based on a comparison of the unfiltered APRM signal to a set point that varies as a function of core flow. When the unfiltered APRM neutron flux signal exceeds the flow-biased set point, a scram signal is generated. An example of the administratively controlled region and the instability region is shown in Figure 4.3-5.

Some plants, like Cooper Nuclear Station, utilize the 3D Monicore Solomon program to monitor and alert the control room operators if the instability region is approached and/or entered.

4.3.3.3 Solution Description Option III

Local Power Range Monitor (LPRM) based Oscillation Power Range Monitor (OPRM), Option III, is a microprocessor-based monitoring and protection system that detects a thermal hydraulic instability and initiates an alarm and ASF before safety limits are exceeded. The OPRM does not affect the design bases for the existing APRMs because it operates in parallel with and is independent of the installed APRM channels.

The algorithms proposed for use in the automatic detection solutions, I-D and III are: High-Low-High Algorithm, Growth Algorithm and Period-Based Algorithm. The High-Low-High Algorithm establishes a setpoint at some value above 100% power. In order to cause a scram the signal must pass through the setpoint with a positive slope followed by passing through the setpoint with a negative slope and then pass the setpoint a second time with a positive slope. When the setpoint is set well above the random fluctuations that occur in reactor operation, this algorithm will prevent scrams that would otherwise result from single spikes. The Growth Algorithm is designed to detect the presence of oscillations as they grow above the level of normal random noise. If the amplitude of an oscillation is greater than the previous oscillations amplitude by a predetermined amount, a scram signal will be generated. The Period-Based Algorithm is the most sensitive of the automatic detection solution algorithms. It detects the "periodicity" of the signal by maintaining statistical data of the intervals between consecutive peaks. When the "periodicity" is high, the reactor is considered to be approaching instability.

Although not part of the BWROG proposed long term solutions, several "Decay Ratio" monitor designs have been developed and used. These on-line monitors can show operators how close the plant is to being unstable and have the same general principles of operation. They use the random fluctuations in the neutron population (reactor noise) to determine the current reactor decay ratio at any given time. The algorithm that is used (determination of the effective decay ratio by using the automatic correlation of the signal) must be time averaged to reduce the fluctuation inherent in this method and to increase its accuracy. Although these are on-line systems, the signal from the monitors is delayed by the averaging time (usually about 2 minutes). The Advanced Neutron Noise Analysis (ANNA) system by Siemens is used at WNP-2. At the present, the monitor at WNP-2 is only used for startup operations. The NRC has granted WNP-2 permission, through a technical specification change, to operate in the old exclusion region C provided the decay ratio monitoring system (ANNA) is in operation. The system was not in use during the oscillation events that occurred at WNP-2. The CASMO system by ABB-Atom and the SIMON system by EuroSim are in use at some foreign BWRs. In Sweden, decay ratio monitors are used at all times since the plants operate in a load following mode and routinely drop flow very close to the exclusion region. Reports indicate that the use of these monitors has prevented many reactor scrams and oscillation events. However, due to their high sensitivity, false alarms are not unusual, and the monitors may indicate high decay ratios when stable conditions exist.

The General Electric supplied NUMAC OPRM System , like the one installed at Plant Hatch, consists of four redundant and separate OPRM channels. Each channel independently monitors for oscillation.

The OPRM system safety trip and oscillation alarms are enabled only when the total recirculation flow value is below 60% and the simulated thermal power is greater than 30%. An alarm is generated when the reactor power and flow conditions enter the region of operation where the OPRM trip is enabled.

All OPRM system signal processing for an OPRM channel is performed by one APRM instrument (Figure 4.3-9) For any particular OPRM instrument, the associated APRM and OPRM channels use the same set of LPRM detector data and the same total recirculation flow data as input. Manual bypass of an APRM channel also causes a bypass of the corresponding OPRM channel.

The OPRM system monitors the thermal-hydraulic instabilities by monitoring the LPRM detector signals since the pressure and flow perturbations which occur during these instabilities cause localized oscillation of the LPRM detector signals. The entire set of LPRM detector signals received by an OPRM channel are divided into "cells" corresponding to a series of local regions in the reactor core which are monitored by the LPRM detectors in those regions.

The high frequency components of the non-bypassed LPRM detector signals assigned to a particular cell are removed by filtering the signals through a low-pass filter. These filtered LPRM detector values are then mathematically averaged together to obtain the characteristic flux value for the cell. This average flux value is passed through another low-pass filter with a 6 second time constant in order to create a time-averaged value of the cell flux. In this manner the cell reference value is normalized to a steady-state value of 1 and is independent of the actual flux value which changes depending on the overall reactor power level.

The cell reference value is supplied to three separate algorithms which test for neutron flux oscillations. These algorithm are the period based algorithm, amplitude algorithm, and the growth rate based algorithm.

The output of the OPRM system (Figure 4.3-10) provides a pre-trip alarm signal based on any of the three algorithms, a safety trip signal based on any of the three algorithms, and the OPRM trip enable alarm signal. The safety trip signal is sent to the safety section of the channel 2/4 logic module. The others are sent to the non-safety section. An OPRM channel INOP signal is generated to alert the operator of any event which compromises the operability of the OPRM channel. OPRM system data is transmitted by the APRM instrument to the process computer via the RBM instrument fiber-optic cabling. The APRM instrument's local display and the associated operator display assembly show pertinent information regarding the operation of the OPRM channel.

4.3.4 Historical Perspective

Evaluation of the probability of thermal-hydraulic instability in BWRs has been an ongoing study by General Electric starting with the first power production plants. Early testing consisted of moving a control rod one notch position while monitoring reactor performance. For BWR/3s, 4s, 5s, and 6s with high power density cores, a pressure disturbance technique was used to cause power instability. The pressure disturbance was accomplished using one of the four turbine control valves. The signal used to control the perturbation amplitude was adjusted to obtain an APRM neutron oscillation within 15% of the steady state signal.

Tests following the instability scrams (one each in 1982 and 1983) at the Caorso Nuclear Power Station (Italian plant), indicated the possibility of power oscillation at high power and low flow conditions. These tests also indicated an out-of-phase neutron flux oscillation and showed that half of the core was oscillating 180 out of phase with respect to the flux oscillation in the other half of the core (as sensed by the LPRMs). These tests also showed that APRMs would not be as sensitive to such a phenomenon. While the LPRMs indicated oscillations of 60% of peak-to-peak power, APRMs indicated oscillations of only 12%.

On February 10, 1984, General Electric issued Service Information Letter (SIL) 380, Revision 1, which discussed the BWR core thermal-hydraulic stability problems that could exist in different variations in all BWRs. The SIL provided a list of recommended actions and identified the high power, low flow corner of the power-to-flow map as the region of least stability and one which should be avoided. If this region of instability was entered, guidance was to insert control rods to reduce reactor power below the 80 percent rod pattern line and monitor LPRMs and APRMs for oscillation.

Generic Letter 86-02 was issued January 1986 to inform licensees of the acceptance criteria for thermal-hydraulic stability margin required in GDC 10 and GDC 12. The objective of the letter was to account for these criteria in future licensing submittals and in safety evaluations in support of 10 CFR 50.59 determinations. It also stated that plants may have to change technical specifications to comply with SIL 380, Rev. 1.

On March 9, 1988 the Unit 2 reactor at the LaSalle Station was operating at 84% steady state power and 76% flow when an instrument technician made a valve lineup error that caused both recirculation pumps to trip. As a result of the rapid power decrease, the EHC system reduced steam flow to the main turbine causing a reduction of extraction steam. The rapid decrease in extraction steam caused severe perturbations in feedwater heater levels which eventually caused isolation of the heater strings. Feedwater temperature decreased 45 F in 4 minutes as a result of this significant reduction in feedwater heating, causing an increased power-to-flow ratio and further reducing the margin to instability. Between 4 and 5 minutes into the event, the APRMs were observed to be oscillating between 25 and 50% power every 2 to 3 seconds accompanied by oscillating LPRM up scale and down scale alarms. The unit automatically scrammed at the 7 minute mark from a fixed APRM scram signal of 118%.

On December 30, 1988 NRC Bulletin 88-07, Supplement 1, dealing with power oscillations in BWRs was issued. The purpose of this supplement was to provide additional information concerning power oscillations in BWRs and to request that licensees take actions to ensure that the safety limit for minimum critical power ratio (MCPR) was not exceeded. In addition, within 30 days of receipt of Supplement 1, all BWRs were required to implement the GE interim stability recommendations derived for GE fuel. The supplement also specified that plants with ineffective automatic scram protection shall manually scram the reactor if both recirculation pumps should trip. Adequate automatic scram protection is available at plants with a flow biased APRM scram with no time delay. Inadequate automatic scram protection is provided at plants with a fixed APRM high flux scram and a separate thermal APRM, time delayed, flow-biased scram.

During the startup of cycle 13, of the Ringhals-1 plant in Sweden in 1989, an unexpected out of-phase oscillation occurred with a peak-to-peak amplitude of about 16 percent. The event was initiated when high neutron flux power level triggered an automatic pump run back from 79 percent power to 68 percent power. An analysis following the event appeared to indicate that the slope of the flow control line was altered by the new fuel cycle and that an increase in recirculation flow resulted in greater-than-expected increases in power.

The Caorso nuclear power station (a BWR/6 located in Italy) experienced an unexpected instability event in 1991. The event occurred during a reactor startup, using GE-7 fuel, and with plant conditions of minimum pump speed, minimum flow control valve position, and a rod pattern line of nearly 80 percent. Actual power and flow values were uncertain but were estimated to be in the range from 38 to 40.8 percent power and from 30.7 to 31.3 percent flow. This event demonstrated that oscillations below the 80 percent rod line are possible and suggested that the regions defined in NRC Bulletin 88-07 may not have been restrictive enough. This event occurred during a startup and was attributed to extreme bottom-peaking of the axial power shape. The feedwater heaters were still cold when the event occurred with a feedwater temperature of approximately 150oF and 56 BTU/lb of subcooling. An interesting effect occurred during the event. The power oscillations continued to grow in amplitude while core power was clearly decreasing as the operator inserted the control rods. The corrective action to avoid repetition of this event was to modify the plant startup procedures to require a hot feedwater temperature before power could be increased above 30 percent power.

On August 15, 1992, Washington Nuclear Power Unit-2 experienced power oscillations during startup. The reactor core for cycle 8 consisted of mostly Siemens fuel (9*9-9x) that has a higher flow resistance than the GE 8*8 fuel. While on the 76% rod line following a power reduction with flow, a power oscillation was observed by the operators who then initiated a scram. An Augmented Inspection Team (AIT) found, by analyses using LAPUR code, that a major contributor was the core loading. The analyses indicated that a full core load of 9*9-9x fuel would be less stable than the old 8*8 fuel and that the mixed core was less stable than a fully loaded core of either type. This event indicated that the boundaries of the instability region defined in the BWROG interim corrective actions may not include all possible areas of instabilities.

4.3.5 Analysis Methods Used For BWR Stability Calculations

Predictive calculations of BWR stability are too complex to allow for simple calculations and require computer codes to simulate the dynamic behavior of the reactor core. The family of codes that has been used to represent and to predict the stability of commercial BWRs can be subdivided in two main categories: frequency-domain and time-domain codes. Among the frequency domain codes are LAPUR, NUFREQ, and FABLE. Time-domain codes are more widely used and include RAMONA-3B, TRAC-BF1, TRAC-G, RETRAN, EPA, SABRE, TRAB, TOSDYN-2, STANDY, and SPDA.

LAPUR was developed at the Oak Ridge National Laboratory (ORNL) for the NRC and is currently used by NRC, ORNL, and others. LAPUR's capabilities include both point kinetics and the first subcritical mode of the neutronics for out of phase oscillations. The thermalhydraulic part is modeled to consider up to seven flow channels with inlet flows coupled dynamically at the upper and lower plena to satisfy the pressure drop boundary condition imposed by the recirculation loop. LAPUR's main result is the open- and closed-loop reactivity-to-power transfer function from which a decay ratio is estimated. Its current version is LAPUR-5.

NUFREQ is a set of codes called NUFREQ-N, NUFREQ-NP, and NUFREQ-NPW that calculate reactor transfer functions for the fundamental oscillation mode The main difference between them is their ability to model pressure as an independent variable (NUFREQ-NP) so that the pressure perturbation tests can be reproduced. NUFREQ-NPW is a proprietary version currently used by Asea Brown Boveri (ABB);

its main feature is an improved fuel model that allows modeling of mixed cores.

FABLE is a proprietary code used by General Electric (GE) which can model up to 24 radial thermal-hydraulic regions that are coupled to point kinetics to estimate the reactor transfer function for the fundamental mode of oscillation.

RAMONA is a code that was developed by ScandPower; it is currently used by Brookhaven National laboratory (BNL), ScandPower, and ABB. The RAMONA-3B version was developed by BNL and has a full three dimensional (3D) neutron kinetics model that is capable of coupling to the channel thermal-hydraulics in a one-to-one basis. Typically, when using time-domain codes, the thermal-hydraulic solution requires orders of magnitude more computational time than the neutronics codes. Because of the large expense associated with the computational time, thermal-hydraulic channels are often averaged into regions to reduce computational time. RAMONA-3B uses an integral momentum solution that significantly reduces the computational time and allows for the use of as many computational channels as necessary to accurately represent the core.

TRAC has two versions currently used in BWR stability analysis. TRAC-BF1 is the open version used mostly by Idaho National Engineering Laboratory (INEL) and Pennsylvania State University, while TRAC-G is a GE-proprietary version. TRAC-BF1 has one dimensional neutron kinetics capabilities (as well as point kinetics). TRAC-G has full 3D neutron kinetics capability (as well as one dimensional and point kinetics), and GE has incorporated most of its proprietary correlations. The numerics in TRAC-G have also been improved with respect to those in TRAC-BF1 to reduce the impact of numerical diffusion and integration errors. Typically TRAC runs are very expensive in computational time; to minimize this time, most runs are limited to the minimum number of thermal-hydraulic regions that will do the job (typically 20).

RETRAN is a time-domain transient code developed by the Electric Power Research Institute (EPRI). It has one dimensional and point kinetics capability and is a relatively fast-running code since it models a single, radial, thermal-hydraulic region and uses the so-called three equation approximation (i.e, it assumes equilibrium between phases). A big advantage of RETRAN over other more detailed tools is that it is capable of running in a desk-top personal computer environment.

Engineering Plant Analyzer (EPA) is a combination of software and hardware that allows for real time simulation of BWR conditions including most of the balance of plant. It was developed for NRC and is located at BNL. EPA's software for BWR stability simulations (named HIPA) models point kinetics with mainly an average thermal-hydraulic region; a hot channel is also modeled but does not provide significant feedback to affect the global results. HIPA uses modeling methods similar to those of RAMONA-3B and, in particular, it uses the integral momentum approach to speed up the thermal-hydraulic calculations. An interesting feature of HIPA is its ability to use time dependent axial power shapes to compute the reactivity feedback. The nodal power shape is varied according to the local void fraction as a function of time based on some polynomial fits that are input to HIPA.

SABRE is a time domain code developed and used by Pennsylvania Power and Light for transient analyses that include BWR instabilities. SABRE uses point kinetics for the neutronics and a single thermal-hydraulic region.

TRAB is a one dimensional neutronics code with an average thermal-hydraulic region. It was developed and used in the Finish Center for Radiation and Nuclear Safety and has been benchmarked against RAMONA-3B calculations and a stability event in the

TVO-I plant.

TOSDYN-2 has been developed and used by Toshiba Corporation. It includes a 3D neutron kinetics model coupled to a five-equation, thermal-hydraulic model and models multiple parallel channels as well as the balance of plant.

STANDY is a time domain code used by Hitachi Ltd. It includes 3D neutron kinetics and parallel channel flow across at most 20 thermal-hydraulic regions. STANDY is a vessel model only and does not include the balance of plant.

SPDA, a combination of RELAP5 and EUREKA, is used by the Japan Institute of Nuclear Safety. RELAP5 calculates the thermal-hydraulic part of the solution, while the nodal power is estimated by EUREKA (which is a 3D neutron kinetics code).

4.3.6 References

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Table 4.3-1 SIL-380

General Electric recommends that BWR operators using GE BWR fuel monitor the inherent neutron flux signals and avoid or control abnormal neutron flux oscillations (with particular attention to the region of sensitivity in where the probability of sustained neutron flux oscillations increase) as follows:

1. Become familiar and aware of your plants normal average power range monitor (APRM) and local power range monitor (LPRM) peak-to-peak neutron flux for all operating regions of the power/flow map and for all operating modes (e.g., two loop and single loop operation). In particular, establish an expected APRM and LPRM peak-to-peak signal for your plant at various operating states and also for special operating modes (single loop operation) if these modes will be used. The expected APRM noise amplitude can be easily determined from past steady state strip chart recordings or can be established based on current operating conditions.

2. Whenever making APRM or LPRM readings, verify that the neutron flux noise level is normal. If there is any abnormal increase in the neutron flux response, follow the recommendation in Section 6d to suppress the abnormal noise signal.

3. The LPRM gains should be properly calibrated per current plant procedures. This will permit the LPRM upscale alarm trip setpoints to be set as high as full scale while providing appropriate indication against unacceptable reduction in thermal margin because of power oscillations. The LPRM upscale alarm indicators should be regularly monitored and all upscale alarms should be investigated to determine the cause and to assure that local limits are not being exceeded.

4. Whenever changes are made or happen that cause reactor power to change, monitor the power change on the APRMs and locally on the LPRMs to become familiar with the expected neutron flux signal characteristics.

5. If a recirculation pump(s) trip event results in operation in the crosshatched region of Figure 4.3-6:

   a. Immediately reduce power by inserting control rods to or below the 80% rod line using the plant's prescribed control rod shutdown insertion sequence.

   b. After inserting control rods, frequently monitor the APRMs and monitor the local regions of the core by using the control rod select switch to display the various LPRM strings which surround the selected control rod. A minimum of nine control rods should be selected to adequately display LPRMs representing each octant of the core and the core center Figure 4.3-7. If there is any abnormal increase in the expected signals, insert additional control rods to suppress the oscillations using the plant's prescribed control rod shutdown insertion sequence.

   c. After inserting control rods, monitor the LPRM upscale alarm indicators and verify (using recommendation 5b) that any LPRM upscale alarms which are received are not the result of neutron flux limit cycle oscillations.

   d. When restarting recirculation pumps (or switching from low to high frequency speed for flow control valve plants), the operation should be performed below the 80% rod line.

Table 4.3-1 SIL-380

e. Once pumps have been restarted and recovery to power is to commence, follow recommendations in Section 6.

6. When withdrawing control rods during startup in dotted region of Figure 4.3-6:

   a. Monitor the APRMs and the LPRMs surrounding control rod movement continually as power is being increased or flow is being reduced for any abnormal increase in the normal neutron flux response.

   b. Monitor the LPRM upscale alarm indicators and verify (using recommendation 5b) that any LPRM upscale alarms which are received are not the result of neutron flux limit cycle oscillations.

   c. Operate the core in as symmetric a mode as possible to avoid asymmetric power distributions. When possible, control rods should be moved in octant (sequence A) and, quadrant mirror (sequence B) symmetric patterns. Control rod movement should be restricted to no more than 2 feet at a time and control rods within a symmetric rod group should be within 2 feet of each other at all times. For BWR/6 plants with ganged rod withdrawal, control rods should be moved in gangs as much as possible to maintain symmetric rod patterns.

   d. If there is any abnormal increase in the normally expected neutron flux response, the variations should be suppressed. It is suggested that the operation which caused the increase in neutron flux response be reversed, if practical, to accomplish this suppression. Control rod insertion or core flow increase (PCIOMRs should be followed during flow increases) will result in moving toward a region of increased stability.

   e. An alternative to recommendations 6 a-d is to increase core flow such that operating in region 2 is avoided. PCIOMR guidelines should still be followed.

7. When performing control rod sequence exchanges:

   a. Follow recommendations 6 a-d, or

   b. Perform control rod sequence exchanges outside of both regions of Figure 4.3-6.

8. When inserting control rods during shutdown, insert control rods to or below the 80% rod line prior to reducing flow into dotted region of Figure 4.3-6 (i.e., avoid corsshatched region during shutdown).

9. Should any abnormal flux oscillations be encountered data should be recorded on the highest speed equipment available and all available power, flow, power shape, feedwater, pressure and rod pattern information documented for subsequent evaluation and operational guidance.

Table 4.3-2 NRCB 88-07 Supplement 1

1. Intentional operation shall not be allowed in Region A or Region B of Figure 4.3-8.

2. Group 1 plant operators shall take immediate actions to exit the region. Immediate action consists of either:

   Insertion of predefined set of control rods which will most effectively reduce core thermal power.

   or

   Increasing recirculation pump speed if one or more pumps are in operation. Starting a recirculation pump to exit this region is NOT an appropriate action.

   Group 2 plant operators shall manually scram the reactor to exit the region.

3. If Region B is unintentionally entered:

   Group 1 and Group 2 operators shall take immediate action to exit the region. Immediate action consists of:

   Insertion of a predefined set of control rods which will most effectively reduce core thermal power.

   or

   Increasing recirculation pump speed or recirculation flow (FCV plants) if one or more pumps are in operation. Starting a recirculation pump or shifting from low to high speed (FCV plants)to exit this region is not an appropriate action.

4. Intentional operation in Region C shall be allowed only for control rod withdrawals during startup requiring PCIOMR. This region should be avoided for control rod sequence exchanges, Surveillance testing and reactor shutdowns.

   During control rod withdrawal, flux monitoring should be conducted in accordance with SIL 380, Revision 1.

5. If at any time during operation in Region A, B, or C, core thermal hydraulic instability occurs, the plant operator shall manually scram the reactor.

   Evidence of thermal hydraulic instability consists of APRM peak to peak oscillations of greater than 10% or periodic LPRM upscale or Downscale alarms in addition to the guidance provided in SIL 380, Revision 1.

Table 4.3-2 NRCB 88-07 Supplement 1

Group 1

Oyster Creek
Nine Mile 1
Dresden 2,3
Millstone
Quad Cities 1,2
Pilgram
Montecello
Duane Arnold
Cooper
Vermont Yankee
Peach Bottom 2,3
Limerick

Group 2

Brunswick 1,2
Hatch 1,2
Browns Ferry 1,2,3
Fermi 2
Fitzpatrick
Hope Creek
Susquehanna 1,2
LaSalle 1,2
Hanford 2
Shoreham
Nine Mile PT 2
Clinton
Perry
Riverbend
Grand Gulf 1

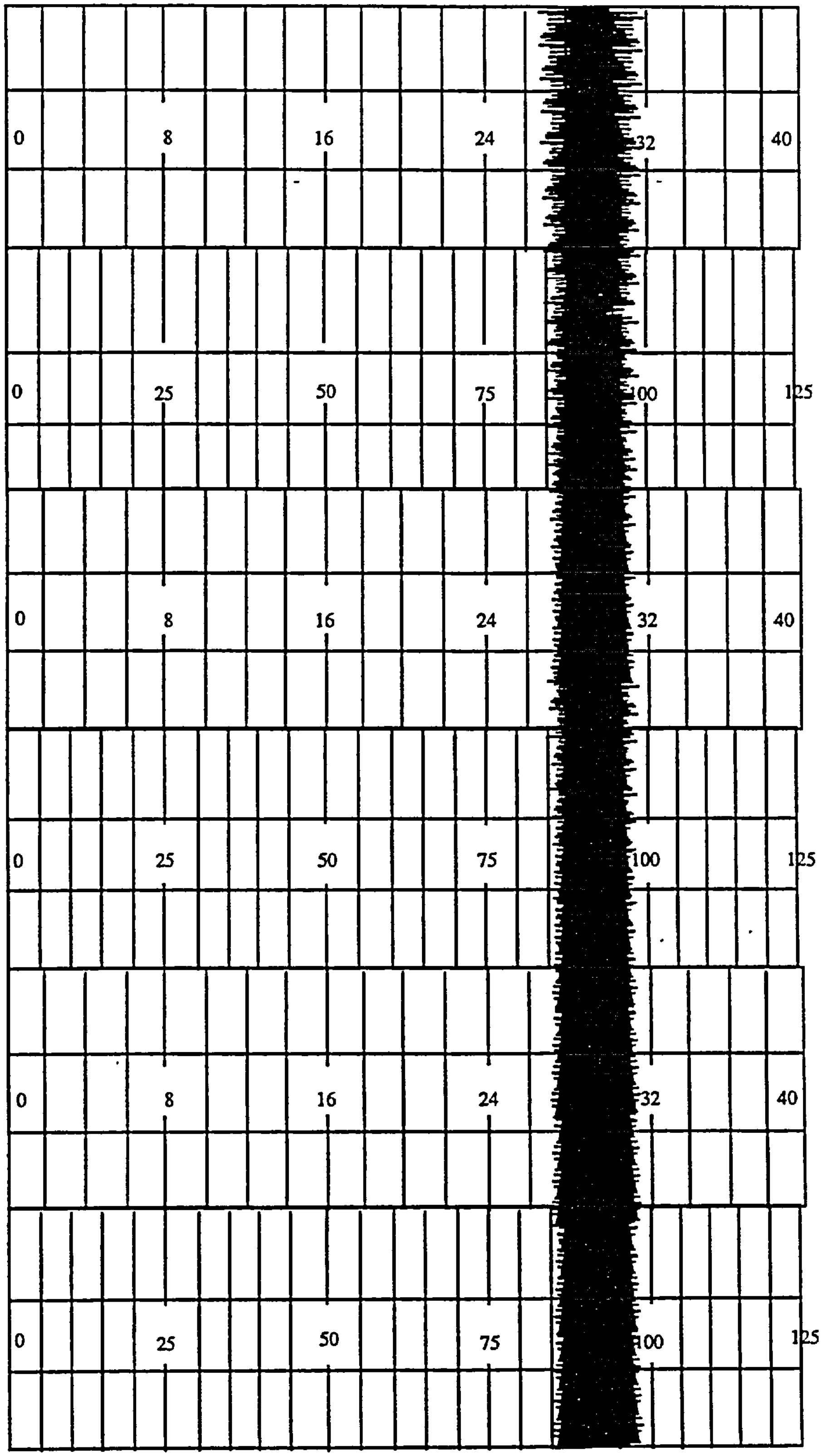
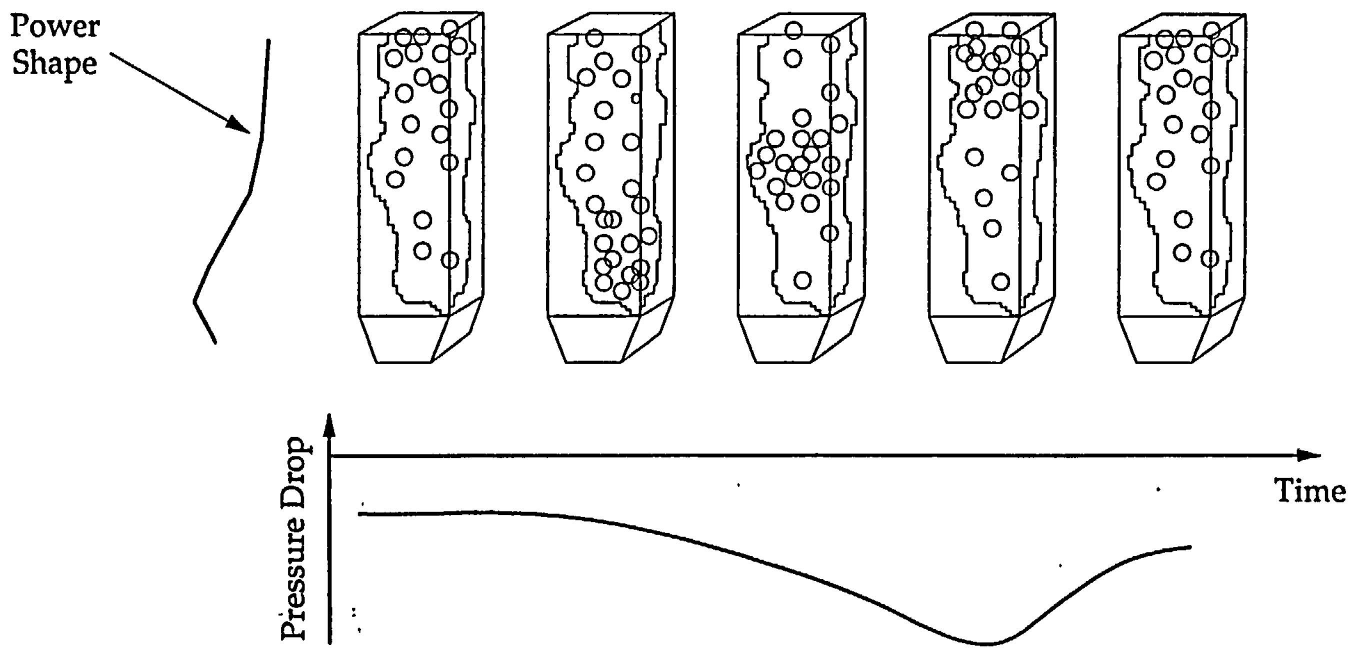


Figure 4.3-1 Normal Observed Power Oscillation on APRMs



NOTE: The effect of a power pulse is seen up to 2 seconds later in the channel pressure drop due to void propagation delay.

Figure 4.3-2 Density Wave Mechanism

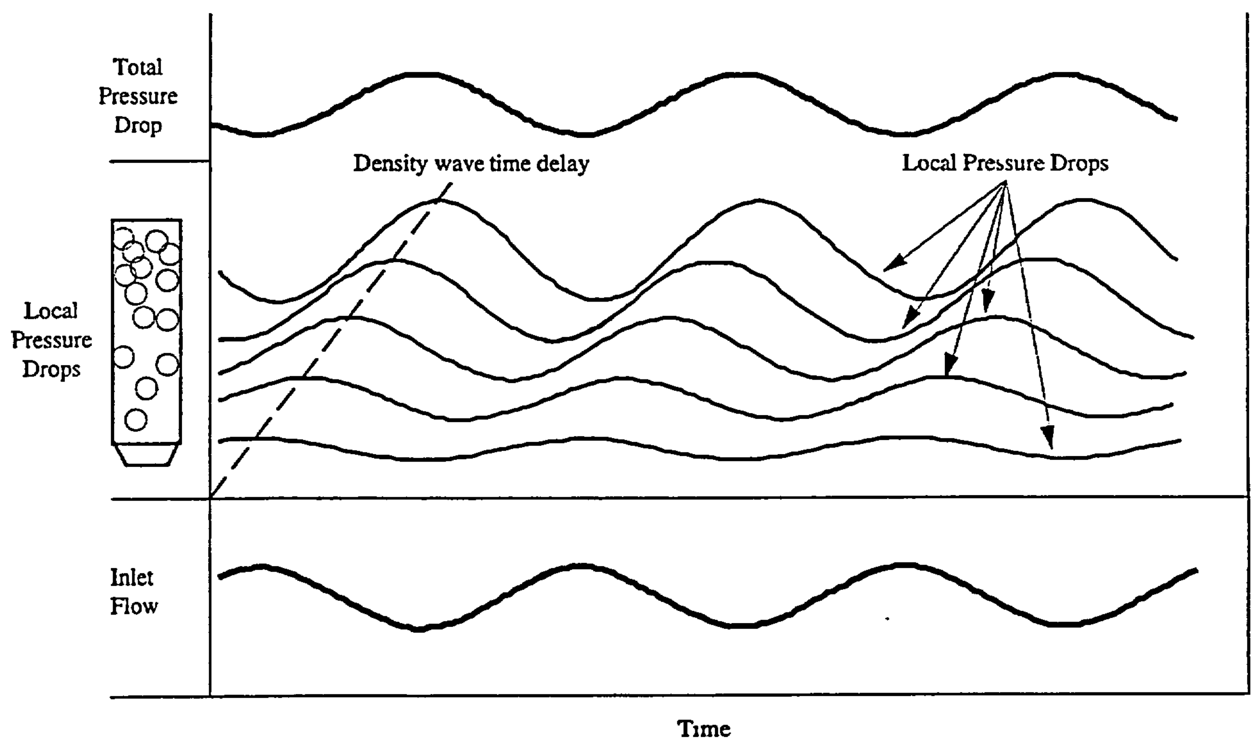


Figure 4.3-3 Sinusoidal Pressure Drop

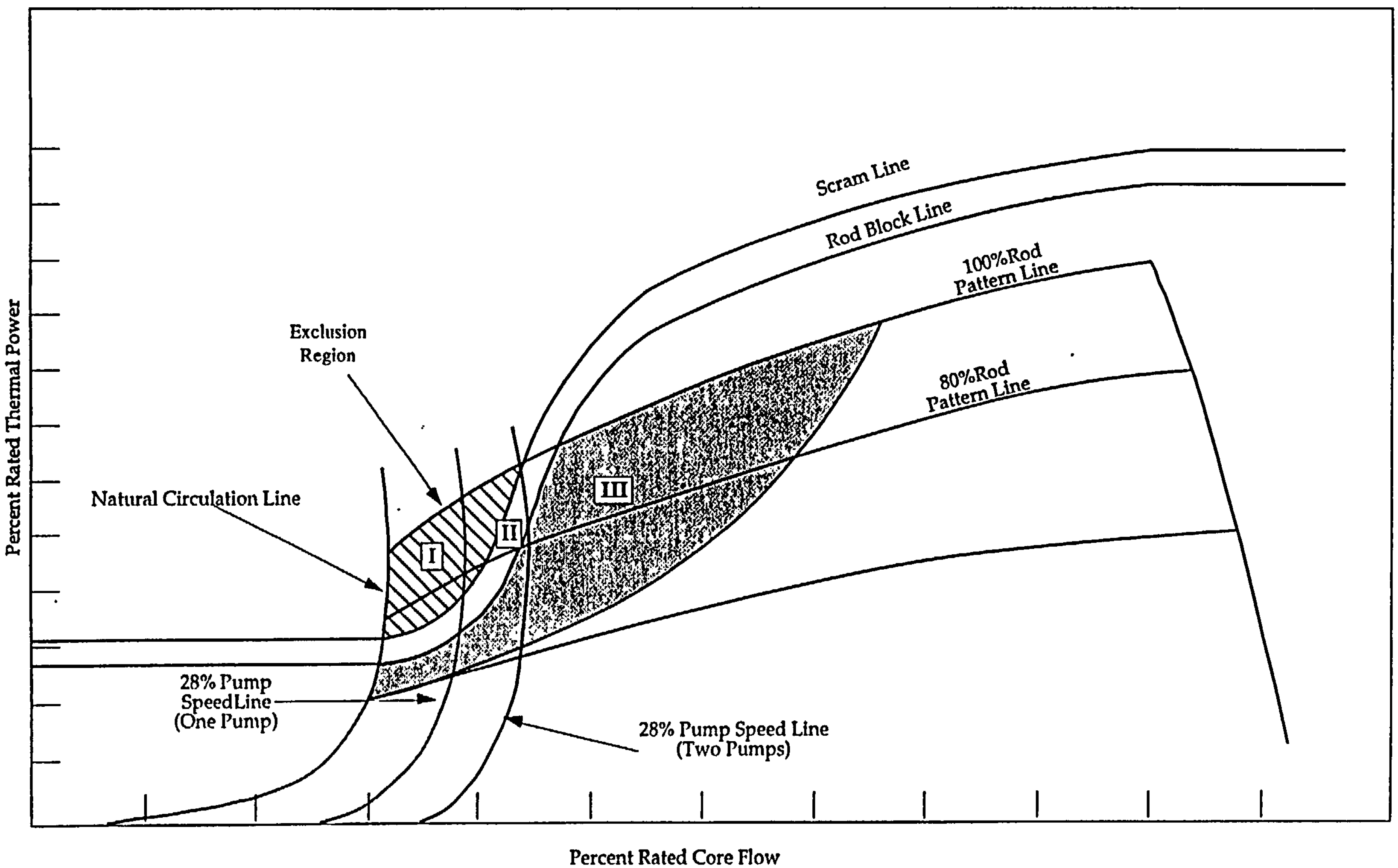


Figure 4.3-4 Reduced Rod Block & Scram Stability Protection for Option I-A

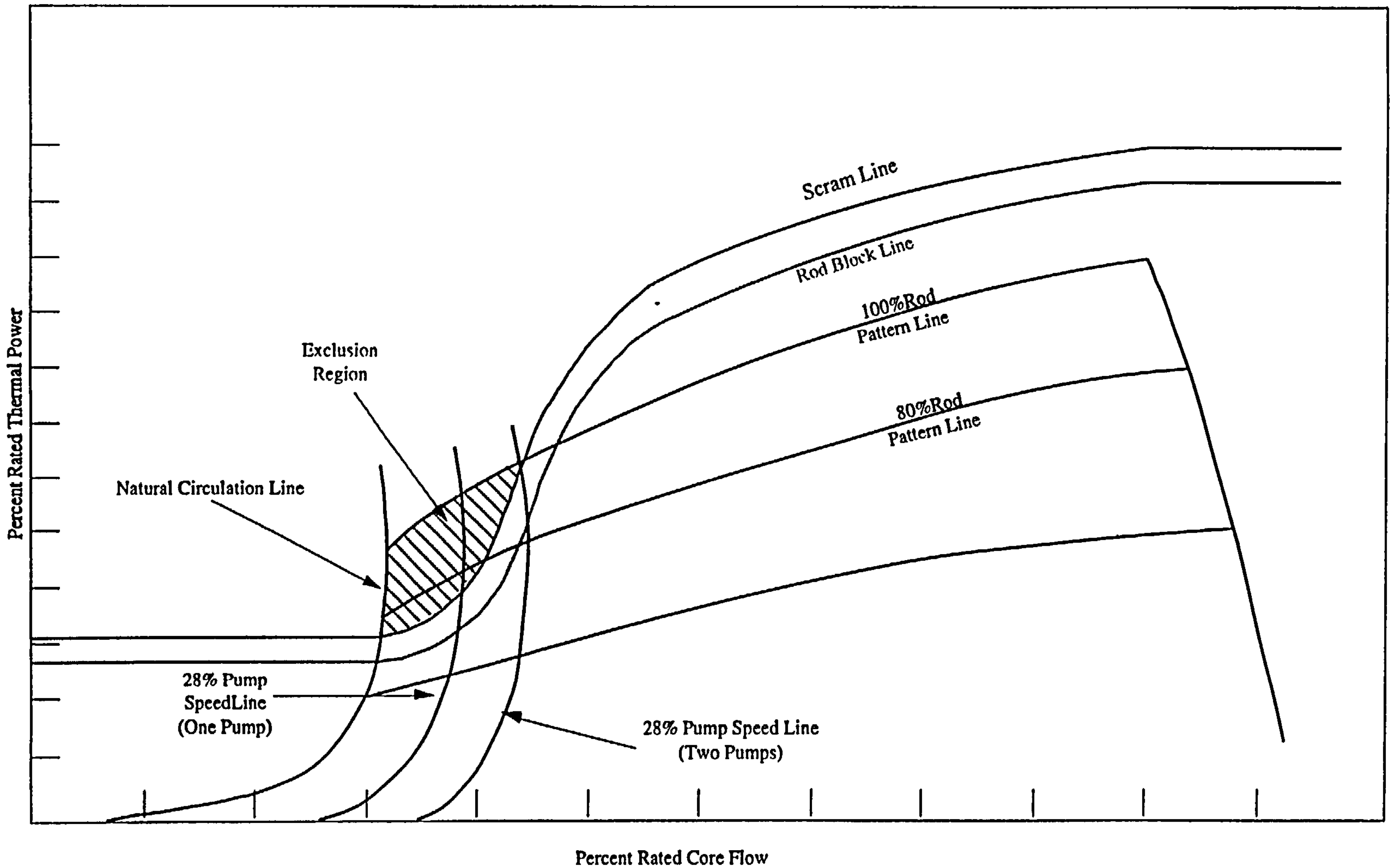


Figure 4.3-5 Administratively Controlled & Instability Region proposed for Option I-D

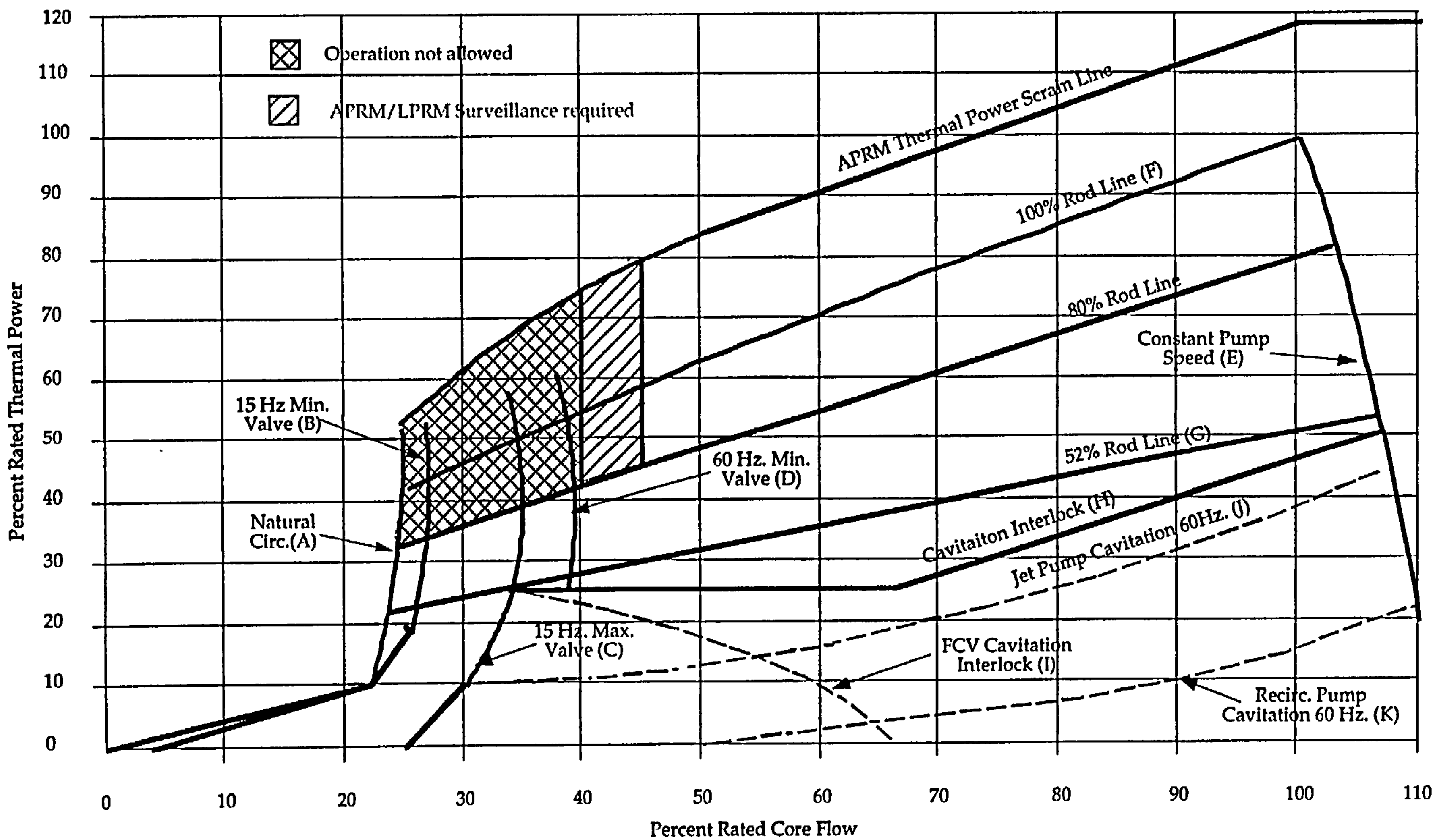


Figure 4.3-6 SIL - 380 Power/Flow Map

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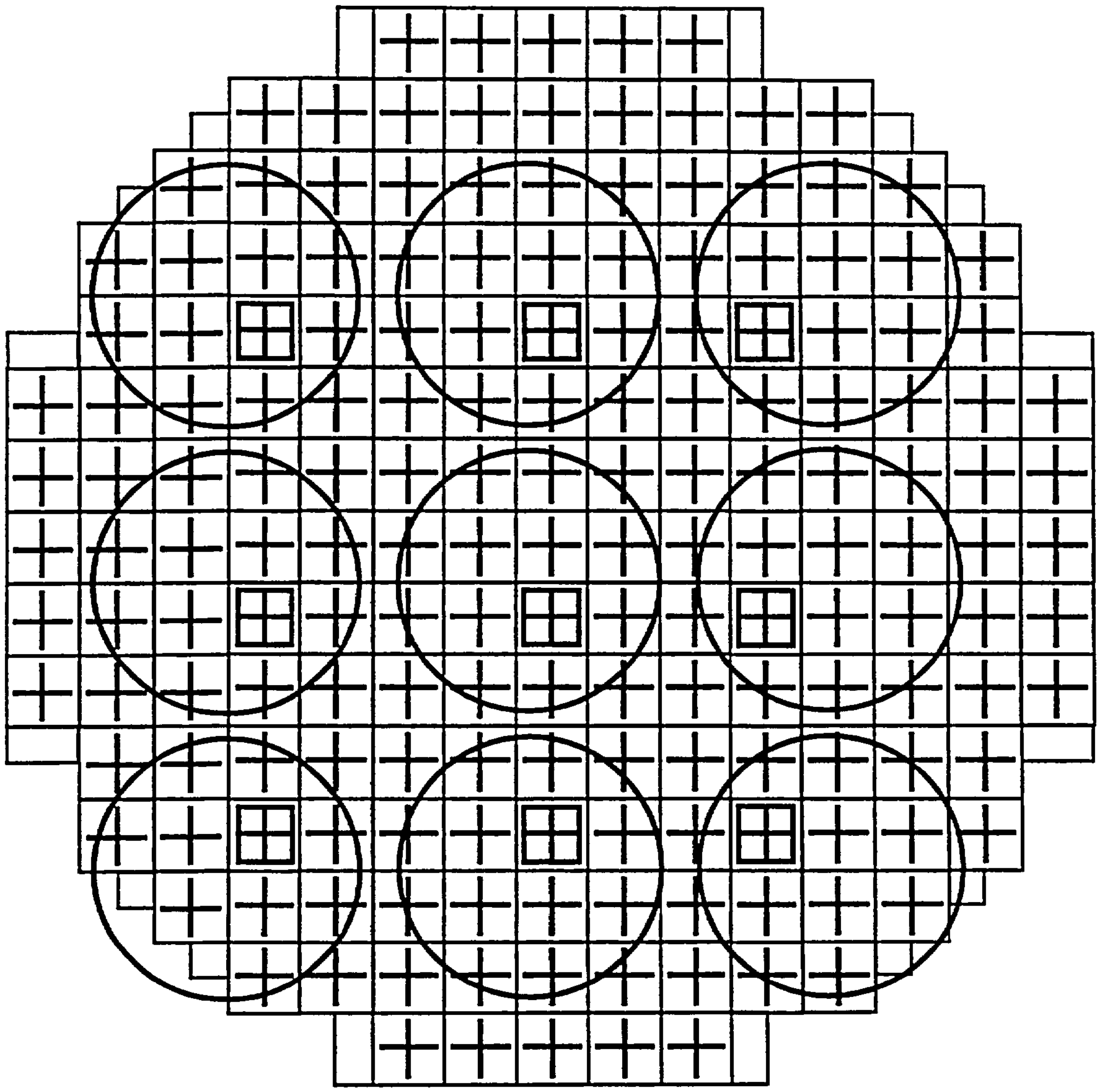

Figure 4.3-7 Typical Local Region Monitoring Scheme

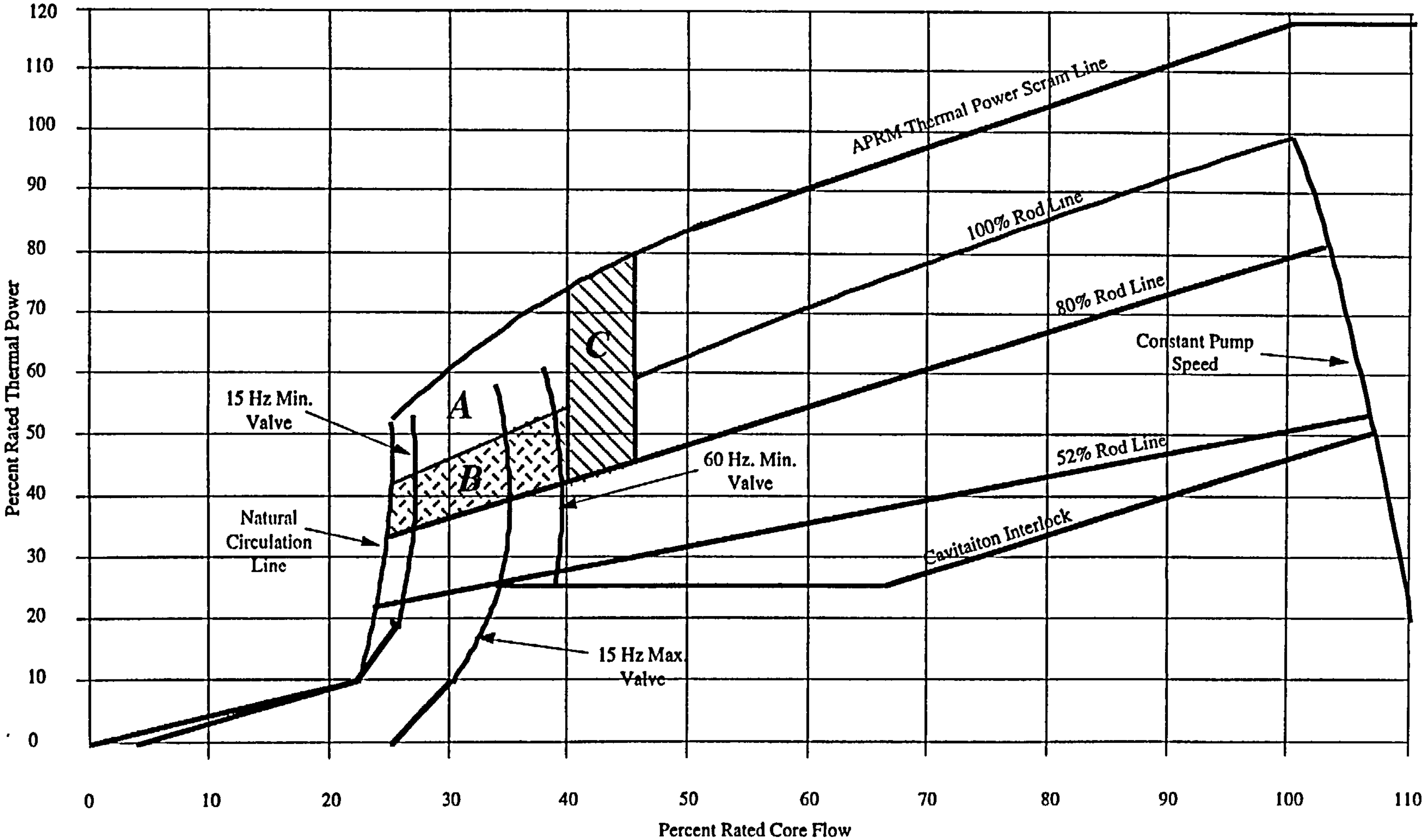

Figure 4.3-8 NRCB Power/Flow

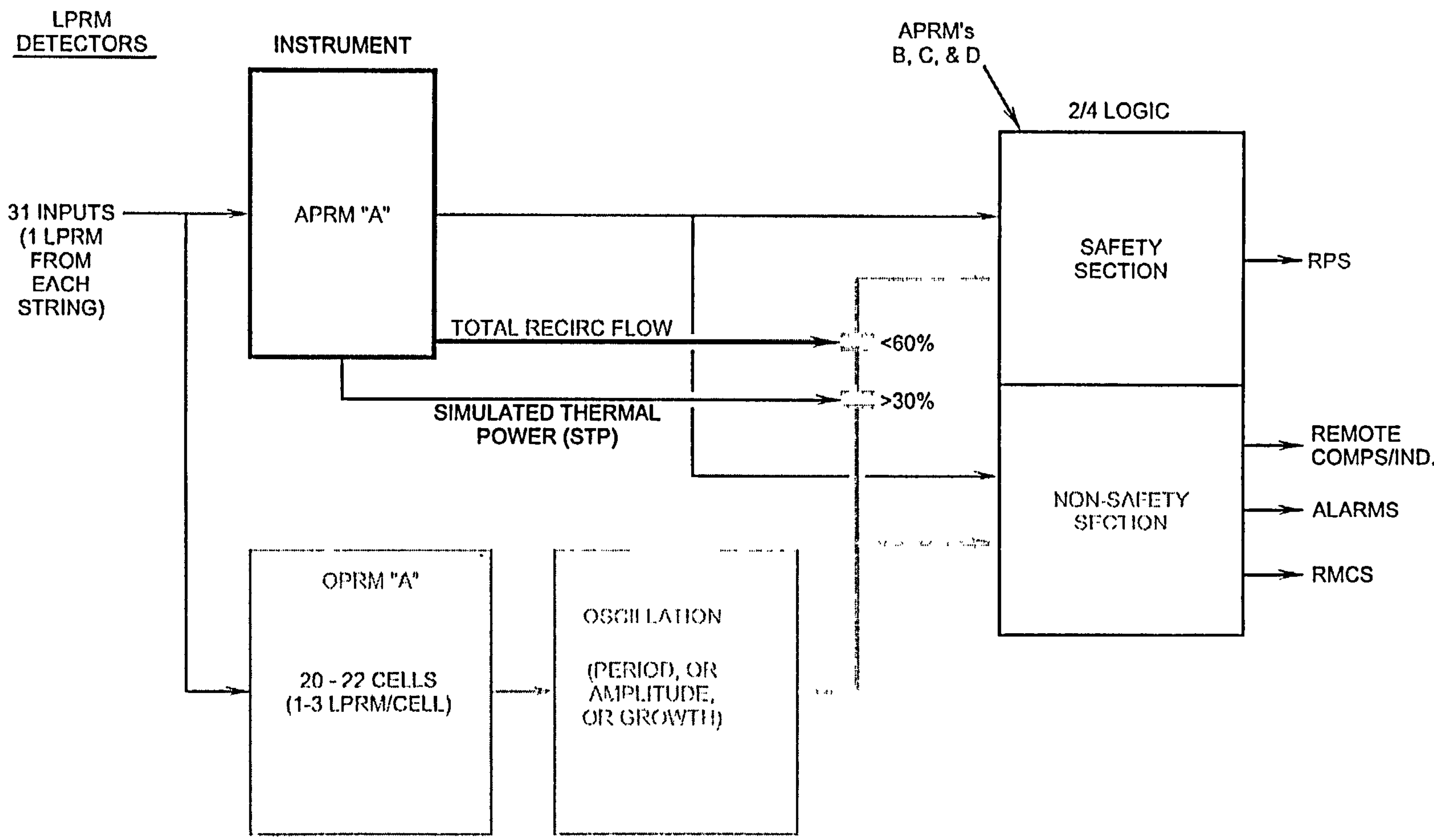

Figure 4.3-9. APRM, OPRM, 2/4 Logic Relationship

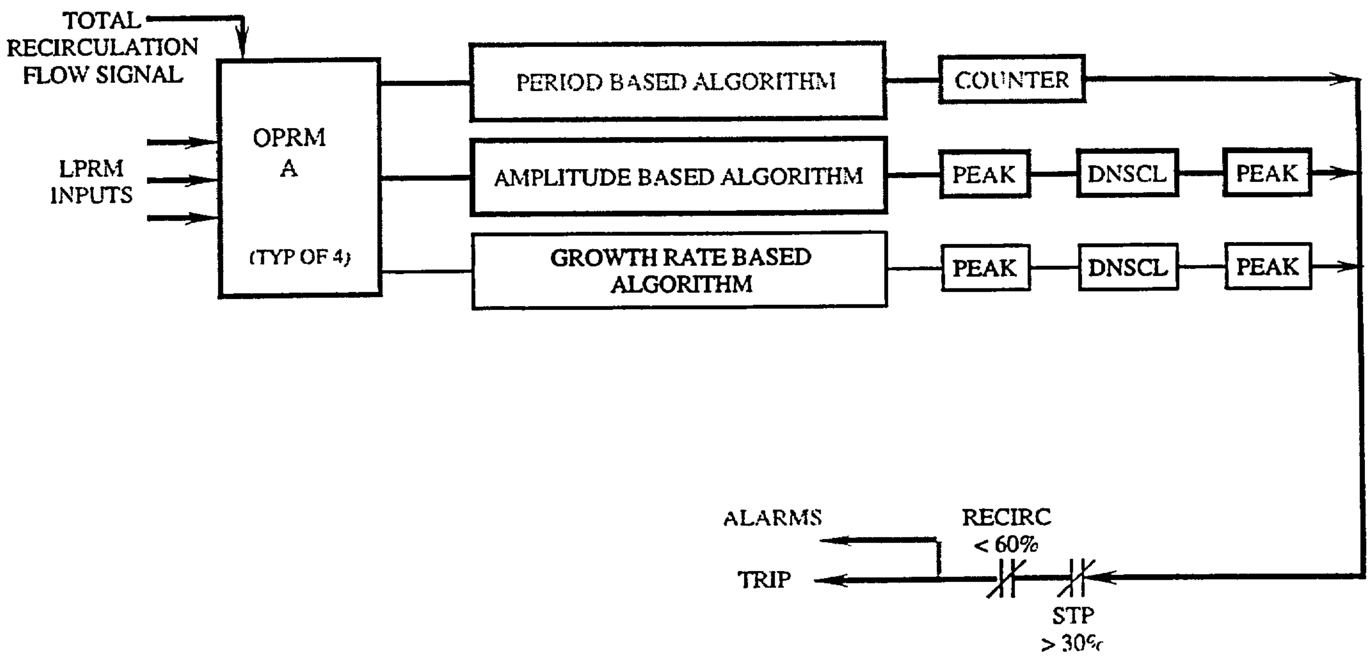

Figure 4.3-10 OPRM Trip Channel

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4.4 PRE-CONDITIONING INTERIM OPERATING MANAGEMENT RECOMMENDATION (PCIOMR)

Learning Objectives :

1. Describe pellet-clad interaction type fuel failure.
2. Explain the purpose of PCIOMR.
3. Describe the basic PCIOMR rules.
4. Define the following terms:
   - threshold
   - PC envelope
   - ramp rate

4.4.1 Introduction

During rapid power increases above previous operating levels, thermal expansion of the fuel pellets can produce Pellet Clad Interaction (PCI) that causes high localized stress in the cladding. When these stresses occur in the presence of fission products, the PCI may cause failure of the cladding. The defects generally appear as longitudinal tight cracks, and for power levels typical of 8x8 fuel designs, occur at exposures beyond 5000 MWd/t.

One of the measures taken to counteract the PCI failure in operating BWRs was a procedure for limiting the number and types of sudden power increases that produce levels above previous operating values. This procedure is called the Preconditioning Interim Operating Management Recommendation (PCIOMR).

The PCIOMR is based on results of plant surveillance, fuel inspections, and individual fuel rod testing in the General Electric Test Reactor (GETR). Tests at GETR in 1971 and 1972 confirmed the mechanism and characteristics of the PCI failures observed in operating BWRs during rapid power increases. Beginning in late 1972 and early 1973 a series of tests in GETR using early production fuel rods demonstrated that a slow ascent to power would not only prevent fuel failure, but that the slow ramp "preconditioned" the fuel to withstand subsequent rapid power changes at all levels up to that attained during the initial slow power increase (PC envelope). These tests served as the bases for the PCIOMR that was introduced in mid-1973.

Subsequent testing, and as surveillance of operating reactor experience, has allowed some modifications to the original procedures. These modifications include more flexibility at low exposures through use of a higher power level (often referred to as the threshold power) for initiation of the preconditioning ramp, by use of maintenance procedure which allows retention of preconditioning for extended exposures. In 1978 a faster preconditioning ramp rate was introduced as a result of testing and analysis of GETR and operating data.

Since its introduction, the PCIOMR has been successfully implemented in operating BWRs throughout the world. The procedure has demonstrated its effectiveness in generally reducing the incidence of PCI failures on the earlier 7x7 fuel designs. In addition, the performance of newer fuel designs has been excellent when the PCIOMR is utilized. Not only has it been proven technically effective, but modifications to the procedure, and introduction of implementation aids and guides have made the PCIOMR a viable means for mitigating the effects of pellet-clad interaction.

4.4.2 Pellet Cladding Interaction

Pellet-clad interaction (PCI) failure of zircaloy clad fuel can occur during rapid power increases in irradiated fuel. Reactor operation produces fuel cracking and radial relocation of pellet fragments and also increases concentrations of fission products such as iodine and cadmium. The differential pellet-clad thermal expansion that occurs during a power increase may then cause pellet-clad interaction with high localized stresses. In the presence of embrittling species (I and Cd), stress corrosion cracking may occur.

The incidence of PCI failures depends on absolute power, rate of increase in power, duration of the power increase, previous power history and burnup. Also, there is a power threshold below which failures do not occur. This power threshold is a function of fuel burnup.

For PCI to occur, both a chemical embrittling agent (fission products I and Cd) and high cladding stresses are necessary. High cladding stresses occur at the pellet-to-pellet interfaces where PCI cracks are most commonly found. Strain concentrations occur in the cladding at radial pellet crack locations. The strain concentration is enhanced where the strain, due to pellet cracks, is also at the location of strain at pellet-to-pellet interfaces. (see Figures 4.4-1, 2, and 3.)

4.4.3 PCIOMR Rules

The General Electric operational recommendations (PCIOMR) are used to reduce PCI failures. Below the threshold power at which PCI failure occurs, there are no limitations on the magnitude, or rate, of power increase. Above the threshold, slow rates of power increases are accomplished by flow control according to PCIOMR guidelines developed from tests in experimental reactors. Following the slow increase to power levels above the threshold a "preconditioned power" level is established which may be utilized for an extended period of time. The PCIOMR rules listed in Table 4.4-3 have significantly reduced PCI fuel failures.

4.4.4 Maintenance of PC Envelope

Initial preconditioning of the fuel, at the beginning of each cycle, cannot be avoided. The preconditioning process itself, namely the slow and controlled increase in local power levels above the preconditioning threshold, must occur at the prescribed rate. At the start of each fuel cycle, the first preconditioning ramp to full power is insufficient to precondition all of the fuel. This is due to some nodes being controlled and, as such, are operating at power levels below the preconditioning threshold. During the first control rod sequence exchange, these low power nodes become uncontrolled and require preconditioning. Hence, a second preconditioning ramp will be necessary. Upon completion of this second ramp, all the fuel will have had an opportunity to be preconditioned. Throughout the remainder of the operating cycle, utilization of proper envelope maintenance and flux shaping techniques will eliminate further preconditioning ramps from low power levels (50 to 75% of rated).

For the purpose of this discussion, the fuel in the core may be regarded as either "A" fuel or "B" fuel as determined by the bundle location in-core. If the bundle is uncontrolled at 50% control rod density in A sequence, then the bundle is A fuel. Likewise, B fuel is uncontrolled at 50% control rod density in B sequence. Note again that during reactor operation in A sequence, all of the A fuel is uncontrolled. During B sequence operation, all of the B fuel is uncontrolled.

Refer to Figure 4.4-8. Assume a beginning-of-cycle startup in the A-1 sequence. At 1,000 MWd/t (core-averaged) cycle exposure, the controlling rod pattern is changed to the B1 sequence. At 2,000 MWd/t cycle exposure, the controlling rod pattern is changed to the A2 sequence and so on as shown. The actual ordering of A1/B1/A2/B2 sequence operation is not important. However, it is essential that the A and B sequences are alternately employed. The A1/B1/A2/B2 sequence that is illustrated here is just one such possibility. As explained later on, preconditioning time will be minimized if the control rod pattern in each sequence results in a bottom-peaked power distribution, preferably Haling or better, at all radial locations.During the beginning-of-cycle startup (Figure 4.4-4 and 5), all fuel will be limited to their exposure dependent preconditioning threshold values.

The exposed fuel will be most limiting due to its having the lowest threshold. There is a shortcut for the beginning-of-cycle startup. It is imperative that the power distribution in the initial sequence be properly bottom peaked. For high power density cores loaded with 7x7 fuel, attainment of a proper bottom peak at the beginning-of-cycle may require more than one preconditioning ramp. All other cores can attain the desired power distribution on the initial ramp.

Upon reaching rated power and completion of the 12-hour soak, the preconditioned envelope should be stored for all nodes. Those nodes which are controlled will not have benefited from the preconditioning ramp just completed. Despite this envelope update, they shall remain limited in power level to their preconditioning threshold values. All of the remaining nodes are uncontrolled and if their peak pin power levels had been preconditioned above their threshold power levels, new preconditioned envelope values will be retained. All of the A fuel (assuming initial operation in A1 or A2 sequence per Figure 4.4-5) and some of the B fuel will therefore have had an opportunity to expand their preconditioned envelope. The A fuel bundles will now have a preconditioned envelope distribution similar to their axial power distribution with the exception of a few nodes near core top and core bottom for which the final power level is still below the preconditioning threshold. Figure 4.4-6 illustrates conversion of the axial power to segment preconditioned envelope values for the A fuel. As for the B fuel, some segments that are situated above the control blade tips may have their preconditioned envelope updated if their final power levels exceed the preconditioning threshold. The important aspect here is that the A fuel, which is wholly uncontrolled, has a valid bottom-peaked preconditioned envelope. Should the reactor be shut down during the first 1,000 MWd/t a rapid return to rated power with the same rod pattern will now be possible utilizing the preconditioned envelope stored at the beginning-of-cycle. If a slower return to rated power is acceptable, it would be best to start up in a new sequence (i.e., B1 or B2 if the beginning-of-cycle start up was in A1 or A2 sequence). This would postpone the sequence exchange scheduled for 1,000 MWd/t cycle exposure until 1,000 MWd/t plus the cycle exposure at the time of the reactor shutdown.

Just prior to reducing core flow and power level for a control rod sequence exchange at 1,000 MWd/t cycle exposure, the preconditioned envelope should again be updated for all nodes. The envelope stored at the beginning-of-cycle will have expired shortly after this power reduction. The preconditioned envelope update at this time constitutes envelope maintenance; the envelope validity will be extended for a second core average exposure of 1,000 MWd/t period. This step is important because it permits utilization of the bottom-peaked preconditioned envelope for the A fuel during the control rod sequence exchange and ensuing power ascension at 2,000 MWd/t cycle exposure.

Following the preconditioned envelope update at the completion of A1 sequence operation, the core thermal power is reduced and a control rod sequence exchange to the B1 sequence is performed. The power ascension in the B1 sequence rod pattern will again be a lengthy preconditioning process. This cannot be avoided because the B fuel segments which were controlled during the A1 sequence operation are now uncontrolled. This fuel will require preconditioning from their preconditioning threshold values.

As in the beginning-of-cycle A1 sequence rod pattern development, it is essential that the necessary time be scheduled to ensure a proper, bottom- peaked power distribution during rated power operation in the new B1 sequence rod pattern. If time is going to be spent on preconditioning, it will be best utilized if the bottom of the core is being preconditioned.

Following this B1 sequence preconditioning envelope update, all of the fuel bundles will have had an opportunity to have its entire axial length preconditioned. The A fuel during A sequence operation; the B fuel during B sequence operation. The preconditioned enveloped formed reflects the maximum power level for each and every fuel segment in the core from either A or B sequence. This resultant preconditioned enveloped is referred to as a composite envelope.

As was the case during the first 1,000 MWd/t period of cycle operation in the A1 sequence, should the reactor scram or be shut down during the present B1 sequence operation, a rapid return to rated power will be possible.

At the close of the 1,000 MWd/t cycle operation in the B1 sequence, it is necessary to update the preconditioned envelope for those nodes and only for those nodes that were updated earlier during the B1 sequence operation. OD-11 has the capability to distinguish these nodes from all other nodes via the nodal delta exposure histogram edit of option 1. (All of the other nodes would have to have been updated at the end of the A1 control rod sequence operation -- the option 1 edit will show the largest value of delta exposure for these nodes. Those nodes that were updated during B1 control rod sequence operation will have smaller values of delta exposure as their preconditioned envelope values were updated more recently.) By updating the B1 sequence nodes, the preconditioned envelope for these nodes will be maintained for another 1,000 MWd/t. That is, their preconditioned values will be valid until the control rod sequence exchange to the B2 sequence and the ensuing power ascension at 3000 MWd/t cycle exposure.

At 2,000 MWd/t cycle exposure, core thermal power is reduced, the control rod pattern is changed to the A2 sequence and core thermal power is increased to rated. During this maneuver, all nodal powers are limited to their preconditioned envelope values. Only those nodes which did not operate at a power level above the threshold level during the A1 and B1 sequences will be limited to the threshold values. If good bottom burns were obtained in both sequences, then all of the fuel will now have large preconditioned envelope values at the core bottom. Once the target A2 control rod pattern is set, core flow can be increased until the first nodal power reaches its preconditioned envelope value. Experience shows that between 80 to 90% of rated core thermal power will be reached before the preconditioning envelope is encountered. The power level attained increases with increased similarity among the previous A1, B1, and present A2 power distributions. The rod positions in the new A2 control rod pattern are irrelevant as long as the power distribution obtained is properly bottom-peaked at all radial locations in the core. The key to successful application of envelope maintenance is to ensure that every control rod pattern utilized results in a good power distribution. The more consistent the core power distribution from sequence to sequence, the faster and easier it will be to return to rated power following a control rod sequence exchange or plant outage.

When rate dower in the A2 sequence is achieved, the preconditioned envelope values stored at the end of A1 sequence operation will no longer be valid as it has been over 1,000 MWd/t since these values were stored. These nodes can be distinguished and updated independently from the nodes whose preconditioned envelope values were updated at the end of B1 sequence operation by using the option 1 histogram edit of OD-11. At this time (in the A2 sequence) all of the A fuel bundles will again be completely uncontrolled. Just prior to the control rod sequence exchange from the B1 sequence, when the preconditioned envelope was updated, all of the B fuel bundles were completely uncontrolled. Hence, this new composition envelope is also comprised of uncontrolled nodal power levels for all of the fuel.

If the preconditioned envelope is properly updated following every ascension to rated power, and if the preconditioned envelope is properly updated prior to each power reduction and control rod sequence exchange, then the stored preconditioned envelope will always (except during the first 1,000 MWd/t cycle exposure) be a composite envelope and each node's preconditioned power level will be determined from its maximum uncontrolled power level. If the plant has the new GE computer code, the plant can go to 2000MWD/t on a nodle bases.

Table 4.4-1 PCI Program

1971	Initiate extensive test and development program.
1972	Initiate design change (7x7R, 8x8)
1973	Implement PCIOMR (7x7R in operation)
1974	Convert to 8x8
1977	8x8R production begins
1979	Prepressurized production starts (P8x8R) Test and Development continues Control Cell Core testing
1981	Barrier Fuel commercial testing

Table 4.4-2 PCI Related Design Changes

Design Change	Benefits
Pellet Geometry eliminate pellet dishing • shorten pellet • chamfer pellet edges	Reduce local clad strain
Cladding Heat Treatment • increase annealing temperature	Reduce variability in clad ductility
8 x 8 Lattice Change	Lower fuel duty • 18.5 kW/ft vs 13.4 kW/ft
Pressurization	Improves pellet-to-cladding gap conductance Lower fuel temperatures Reduced UO_2 thermal expansion reduced fission gas release
Control Cell Core	Simplified operation
Barrier Commercial test	PCI Resistant

Table 4.4-3 PCIOMR Rules

1	No constraints below preconditioning threshold.
2	Preconditioning threshold is exposure dependent.
3	Limit control rod movement above threshold.
4	Rod withdrawal over threshold permitted one notch every two minutes.
5	For xenon or burnup, one notch every 12 hours.
6	Rate of power increase with flow at .11 kW/ft/hr above threshold.
7	Ramp rate permitted at .12 kW/ft/hr if over four hours.
8	Maximum ramp increase at .2 kW/ft (one step).
9	.3 kW/ft over envelope permitted during xenon transient (no control rod movement or flow increase).
10	Power increases at 15 % power/minute with flow permitted if below preconditioned level.
11	Soak 12 hours to establish preconditioning envelope when desired power level is obtained.
12	Envelope is good for 1,000 MWD/T after leaving the envelope. Establish new envelope after 1,000 MWD/T.
13	Can preserve the envelope for 1,000 MWD/T if you soak at the envelope in 72 out-of 96 hours.

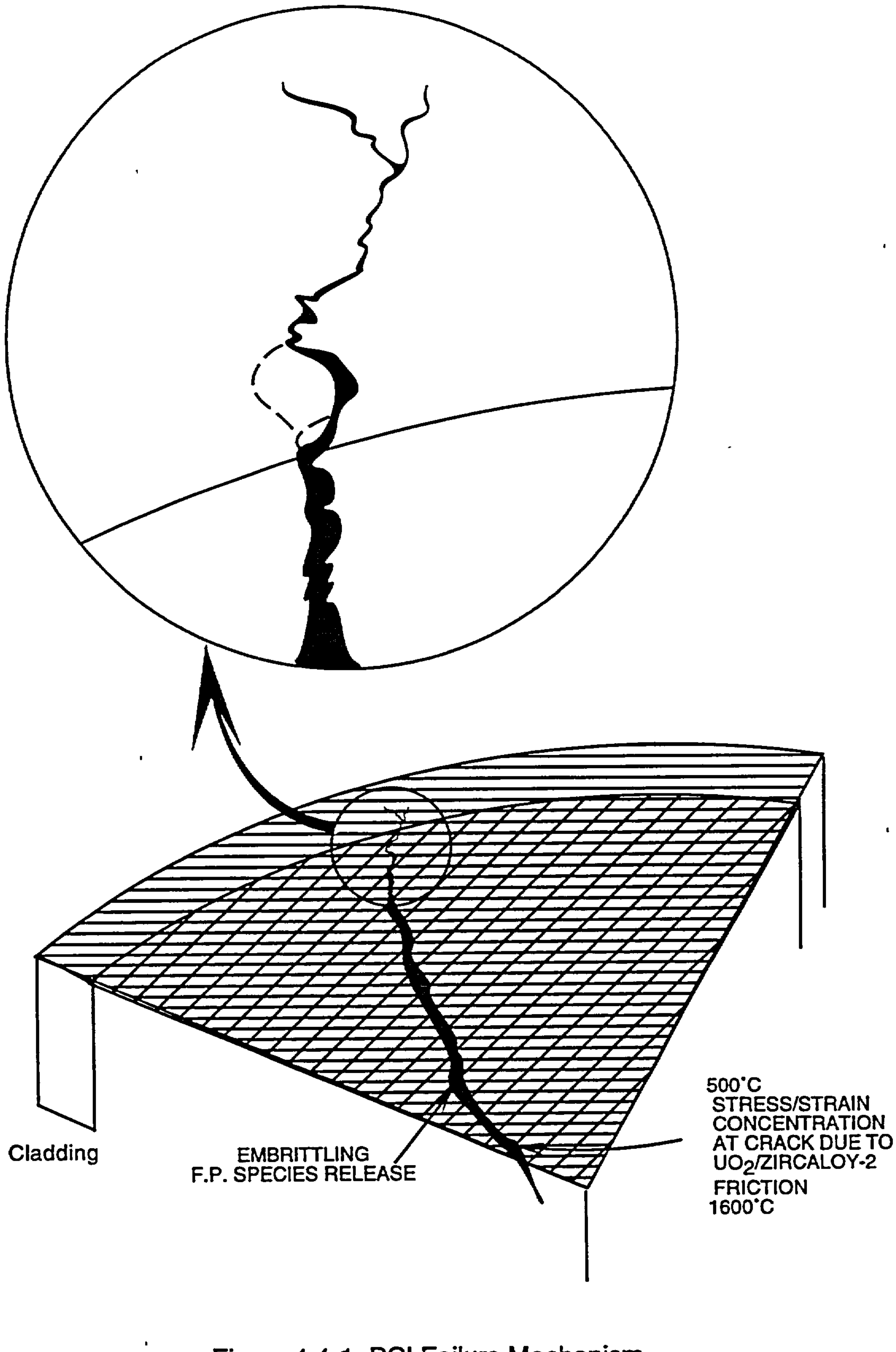


Figure 4.4-1 PCI Failure Mechanism

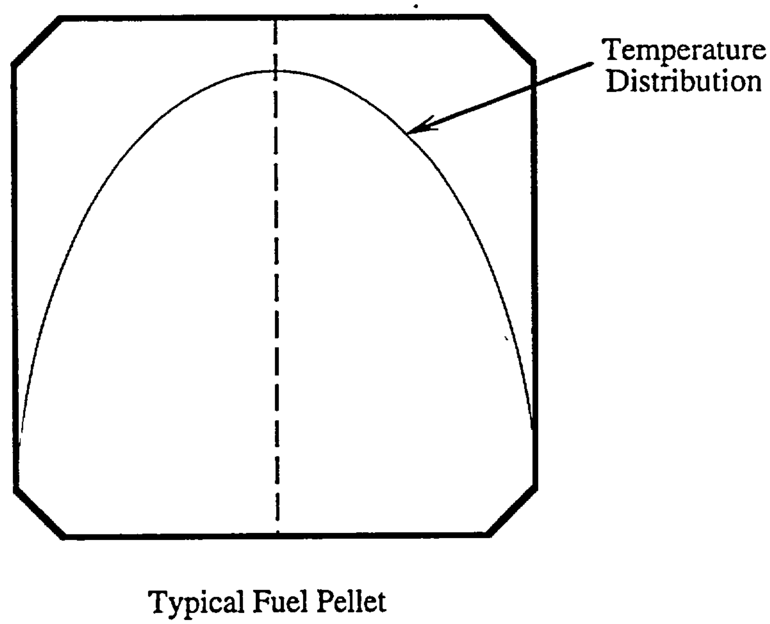
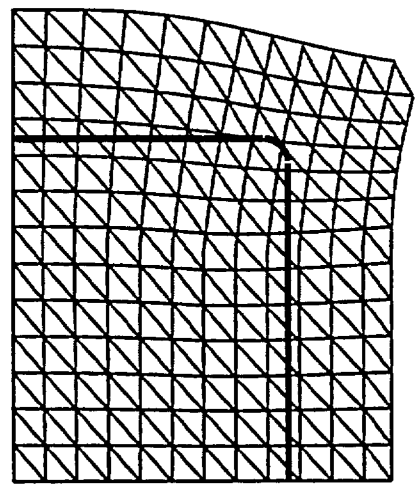


Figure 4.4-2 Typical Temperature Distribution



Chamfered Pellet

Pellet Thermal Distortion

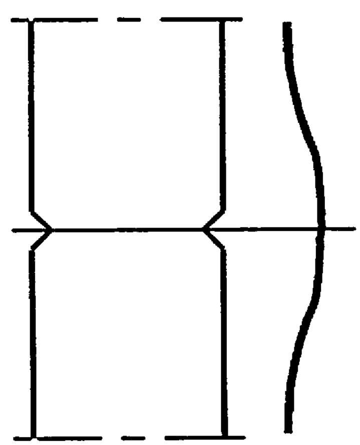


Figure 4.4-3 Pellet-Clad Interaction

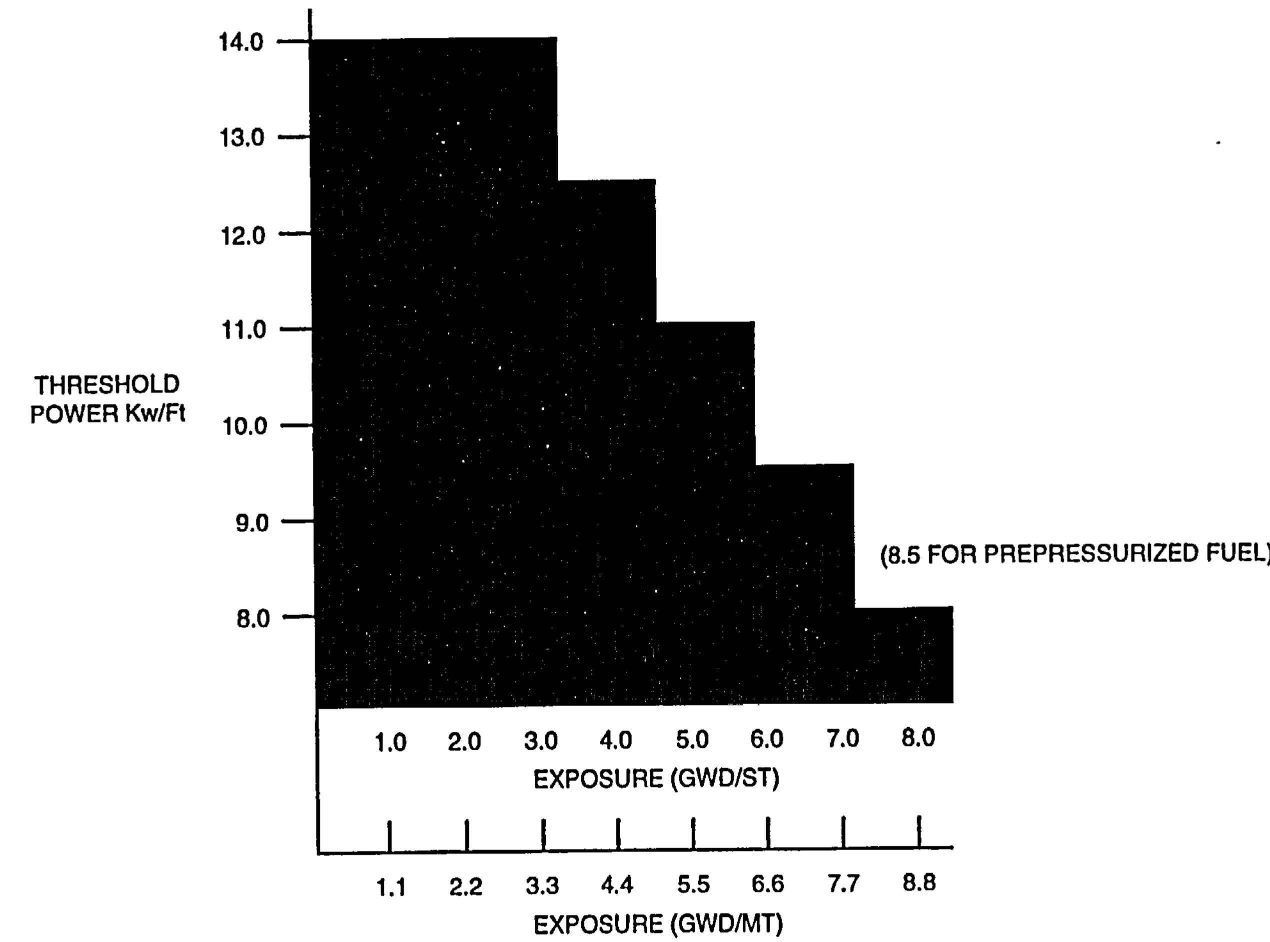


Figure 4.4-4 Preconditioning Threshold

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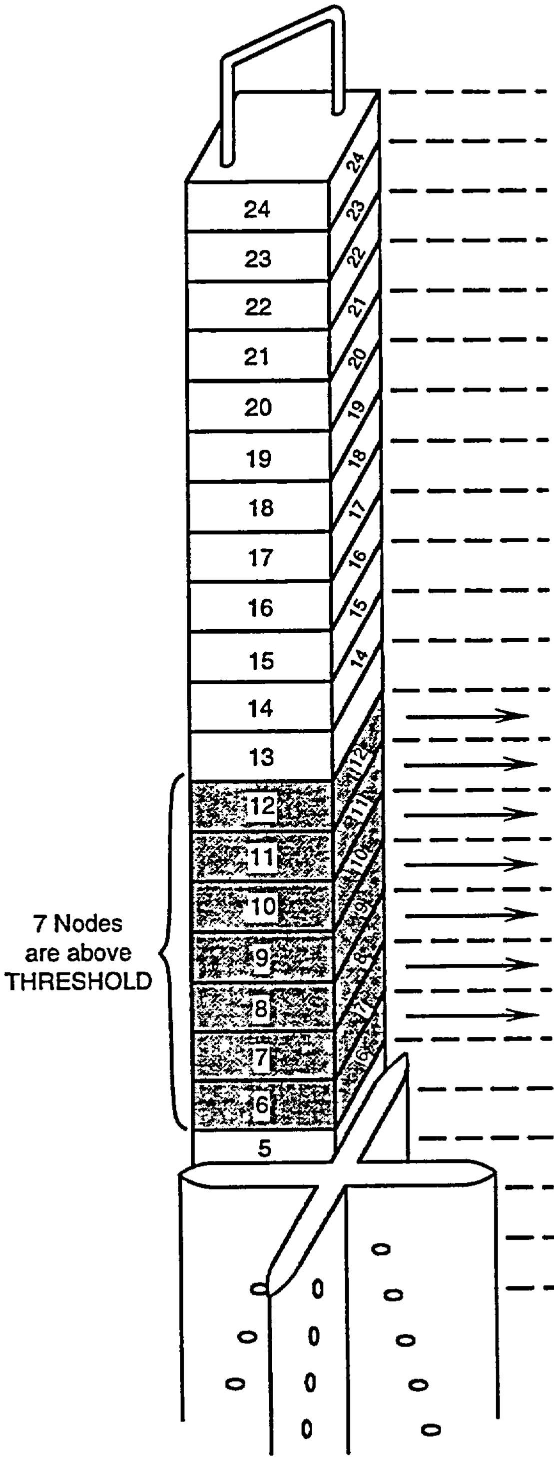


NODAL POWER kw/ft	THRESHOLD kw/ft	ENVELOPE
3.2	8.0	8.0
3.3	8.0	8.0
3.4	8.0	8.0
3.5	8.0	8.0
3.7	8.0	8.0
3.9	8.0	8.0
4.0	8.0	8.0
4.2	8.0	8.0
5.0	8.0	8.0
6.1	8.0	8.0
6.9	8.0	8.0
7.5	8.0	8.0
8.1	8.0	8.1
8.4	8.0	8 4
8.8	8.0	8.8
9.0	8.0	9.0
9.3	8.0	9.3
8.9	8.0	8.9
8.4	8.0	8.4
7.8	8.0	8.0
2.8	8.0	8.0
2.7	8.0	8.0
2.4	8.0	8.0
2.3	8 0	8.0

Figure 4.4-5 Fuel Assembly Nodal Power/Threshold/Envelop

Lattice	6x6	7x7	7x7R	8x8	8x8R	P8x8R				→
Clad	SS	Zr-2				Zr-21 Barrier				→
Designation		GE-2	GE-3	GE-4	GE-5	GE-6	GE-7	GE-8	GE-9	GE-10
Introduced		68	73	74	77	79	83	86	88	89
Active Fuel Level		144	146	148	150					→
GWs/Mt Peak Pin Exp.	—	—	—	—	—	—	~45	65		→
#Gd_2O_3 Rods, Max	—	—	—	—	—	—	8	12	13	
Axial Gd-Reloads	—	—	—	—	—	—	—	√	√	√
Axial Enrichment	—	—	—	—	—	—	—	—	√	√
Max. Pellet Enr.	—	—	—	—	—	3.95			→	4.95?

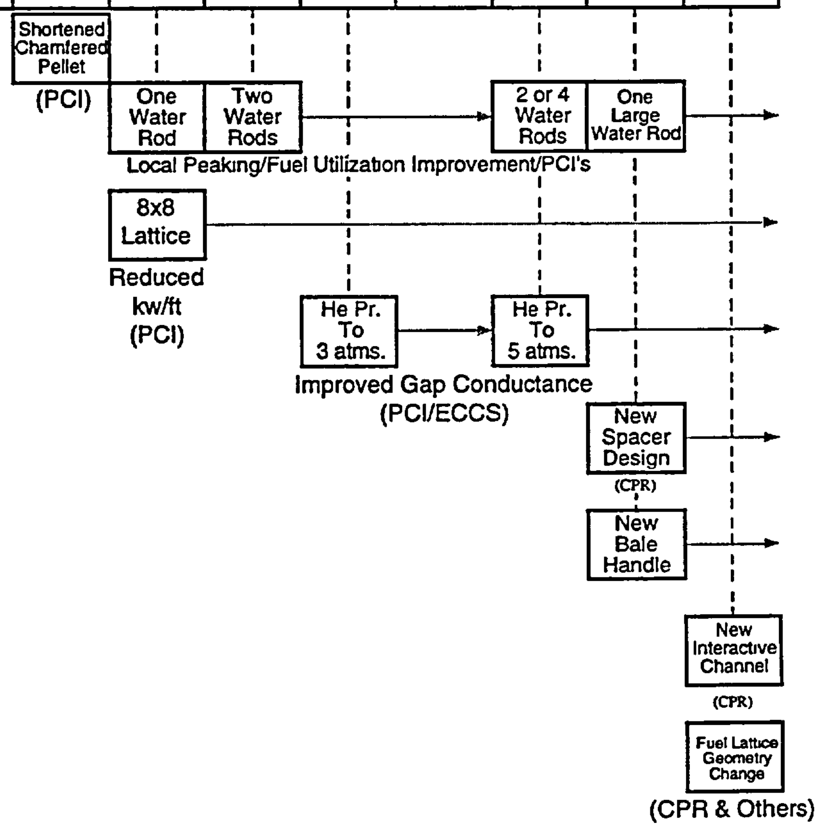


Figure 4.4-6 Fuel Design Evolution

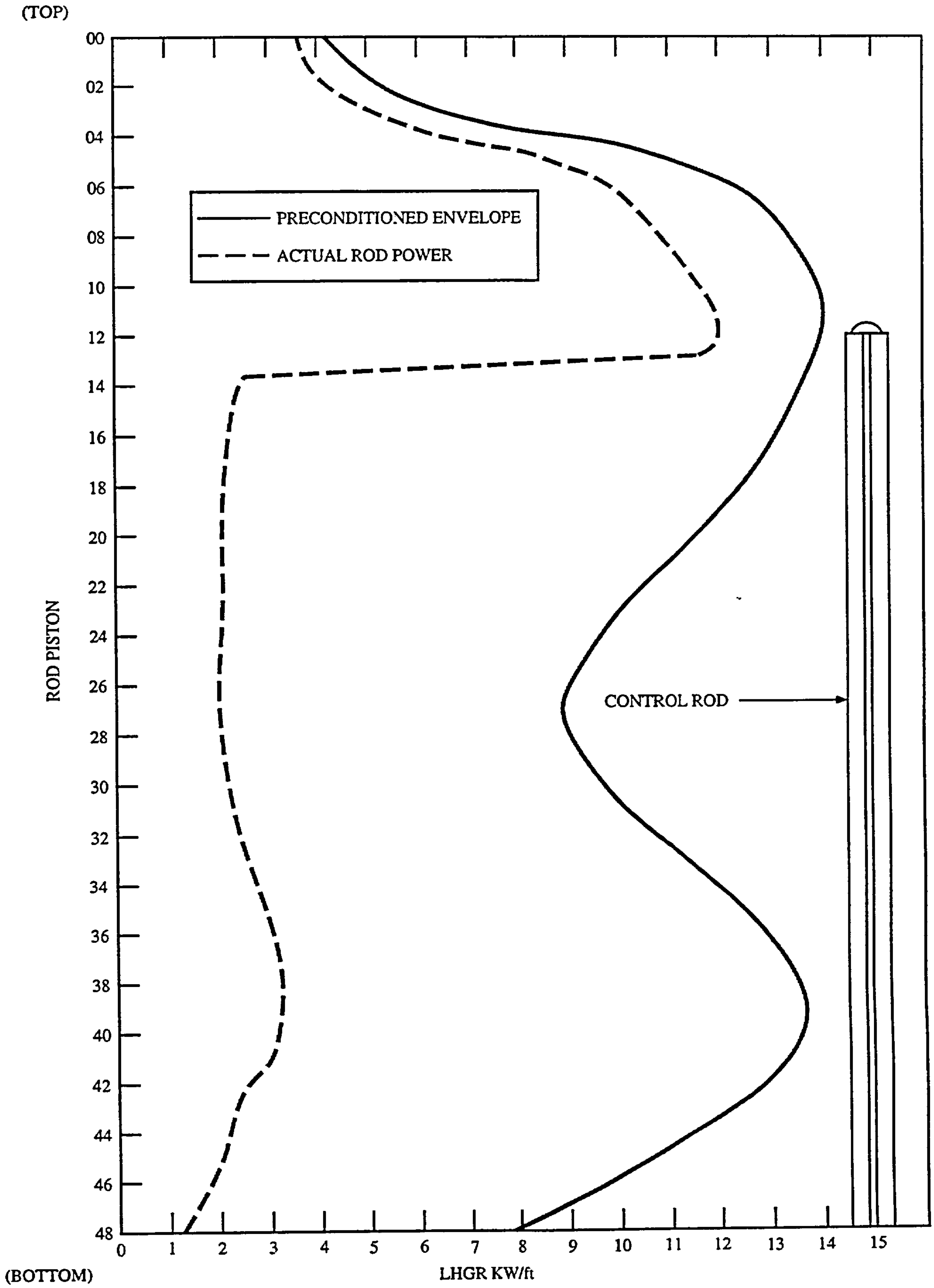
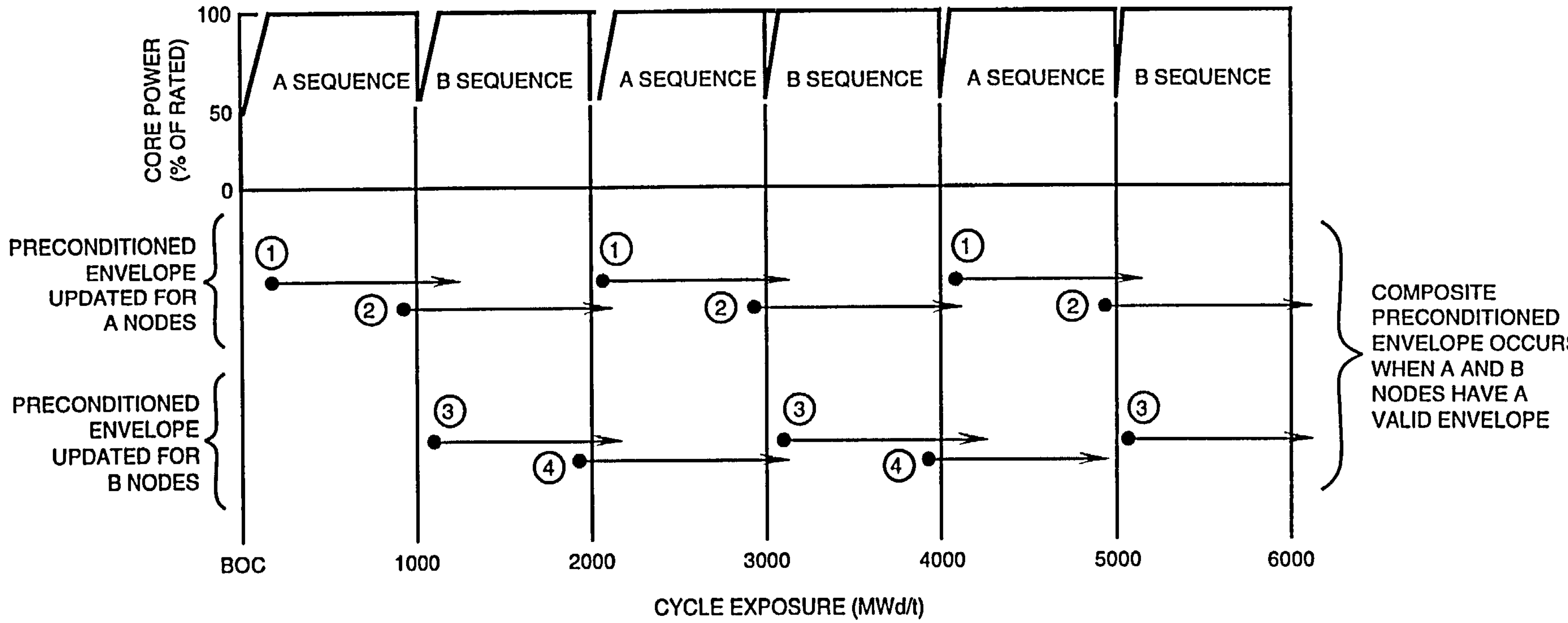


Figure 4.4-7 Preconditioned Envelope and Actual Rod Power



(1) START OF A SEQUENCE OPERATION AT RATED POWER. THE PRECONDITIONED ENVELOPE IS STORED. ALL A FUEL IS UNCONTROLLED AT THIS TIME.

(2) END OF A SEQUENCE OPERATION. HAVING SATISFIED THE ENVELOPE MAINTENANCE CRITERION FOR PRECONDITIONED ENVELOPE STORAGE, THE PRECONDITIONED ENVELOPE VALUES STORED AT (1) ARE UPDATED THEREBY EXTENDING THE ENVELOPE VALIDITY FOR THESE NODES FOR AN ADDITIONAL 1000 MWd/t CYCLE EXPOSURE.

(3) START OF B SEQUENCE OPERATION AT RATED POWER. THE PRECONDITIONED ENVELOPE IS STORED. ALL B FUEL IS UNCONTROLLED AT THIS TIME.

(4) END OF B SEQUENCE OPERATION. HAVING SATISFIED THE ENVELOPE MAINTENANCE CRITERION FOR PRECONDITIONED ENVELOPE STORAGE, THE PRECONDITIONED ENVELOPE VALUES STORE AT (3) ARE UPDATED THEREBY EXTENDING THE ENVELOPE'S VALIDITY FOR THESE NODES FOR AN ADDITIONAL 1000 MWd/t CYCLE EXPOSURE.

Figure 4.4-8 Strategy for Maintaining a Composite Envelope

0397-4

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4.5 LOSS OF ALL AC POWER (STATION BLACKOUT)

Learning Objectives :

1. Define the term station blackout.

2. Describe the impact a station blackout would have when combined with an accident.

3. Describe the primary method available to mitigate the consequences of a station blackout.

4. List the two major classifications Boiling Water Reactors have been divided into for discussing station blackouts.

4.5.1 Introduction

The general design criteria (GDC) in Appendix A of 10CFR50 establish the necessary design, fabrication, construction, testing and performance requirements for structures, systems, and components important to safety; that is, structures, systems and components that provide reasonable assurance that the facility can be operated without undue risk to the health and safety of the public. GDC 17 "Electric Power Systems" requires that an onsite and offsite electric power system shall be provided to permit functioning of structures, systems and components important to safety. These structures, systems and components are required to remain functional to ensure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences. The GDC goes further to specify additional requirements for both the onsite and offsite electrical power distribution systems to ensure both their availability and reliability.

The establishment of GDC 17 was considered sufficient to ensure that commercial nuclear power plants could be built and operated without undue risk to the health and safety of the public. The likelihood of a simultaneous loss of offsite and onsite sources of ac power was considered incredible and therefore did not have to be considered in plant design or accident analysis. Evaluation of plant data and events along with insights developed from PRA analysis have led to the development and implementation of additional regulatory requirements addressing station balckout.

4.5.2 Description of Electrical Distribution System

A diagram of a typical offsite power system used at a nuclear plant is shown in Figure 4.5-1. During plant operation, power is supplied to the Class 1E (onsite) distribution system from the output of the main generator. In the event of a unit trip, the preferred source of power to the onsite distribution system would be the offsite grid. If offsite power is available, automatic transfer to the preferred power source will ensure a continuous source of ac power to equipment required to maintain the plant in hot standby and remove decay heat from the core. If offsite power is not available due to external causes such as severe weather or equipment failure, the onsite distribution system would sense the undervoltage condition and initiate a transfer to the onsite (standby) power source. Figure 4.5-2 shows a typical onsite emergency ac power distribution system. In the event that an undervoltage condition is sensed on the emergency buses following a unit trip, the system is designed to open all supply breakers to the buses, disconnect all unnecessary loads, start the emergency diesel generators and reconnect all loads necessary to maintain the plant in a stable hot shutdown condition. If the onsite emergency ac power source is not available to re-energize the onsite system, a station blackout has occurred.

4.5.3 Offsite Power Systems

On November 9, 1965, the northeastern U.S. experienced a power failure which directly affected 30 million people in the U.S. and Canada. On July 13, 1977, New York City experienced a blackout, following lightning strikes in the Indian Point 3 switchyard causing the reactor to scram and the plant to lose offsite power. No Federal regulation of the reliability of the bulk power supply was provided by the Federal Power Act of 1935 and none was subsequently approved following either the 1965 or the 1977 incidents. The reliability of the bulk power supply (interconnections) is the responsibility of the North American Electrical Reliability Council through its member Reliability Councils. These Councils are made up of members representing the electric power utilities which engage in bulk power generation and transmission in the United States, Canada, and Mexico.

Figure 4.5-3 Shows the geographic locations of the member councils throughout the United States and the various interconnections sections. Interconnections is a strategy for providing power from the plants via an interconnected transmission network to the entities that resell it to the consumer via a distribution network. The Western Interconnection is composed of one reliability Council, Western Systems Coordinating Council. The Eastern Interconnection is comprised of East Central Electric Reliability Coordination Agreement, Mid-Atlantic Area Council, Mid-America Interpool Network, Mid-America Power Pool, Northeast Power Coordination Council, Southeastern Electric Reliability Council, and Southwest Power Pool. The Texas Interconnection is also composed of one reliability Council, Electric Reliability Council of Texas.

The objectives for each Reliability Council vary but, whether explicitly stated or implied in context, the Reliability Councils' operating philosophy is to prevent a cascading failure, provide reliable power supplies, and maintain the integrity of the system. Long-term and short-term procedures are in place nationwide to project demand, to provide for reserves to meet peak demand, and to provide for both likely and unlikely contingencies when demand exceeds capacity and other emergencies. These procedures include a load reduction program and automatic actuation to prevent collapse of the grid. The load management procedures for mid-Atlantic Area Council consist of:

- Curtailment of nonessential power company station light and power (power plants)
- Reduction of controllable interruptible/reducible loads
- Voltage reductions (brownouts)
- Reduction of nonessential load in power company buildings (other than power plants)
- Voluntary customer load reduction
- Radio and television load reduction appeal
- Manual load shedding (rotating blackouts)
- Automatic actuation of underfrequency relays which shed 10 percent of load at 59.3 Hz, and additional 10 percent at 58.9 Hz, and an additional 10 percent at 58.5 Hz.

Other procedures allow disconnecting from the grid areas which have generating units that are capable of supplying local loads, but would trip if connected to a degrading grid.

In addition, emergency procedures are provided for the safe shutdown and restart of the system. Because many plants cannot be restarted without external power, "black start" units are available at various locations as determined by the utility. The black start units are capable of self-excitation: therefore, they restart and produce power to restart other units. The typical black start capability is comprised of diesel generators, combustion turbine units, conventional hydro units, and pump storage units. Normal operating procedures for pump storage hydro plants require maintaining sufficient water in the upper reservoir at all times to provide for system startup power. Satisfactory tests have been conducted to prove the capability of black start of conventual hydro, pumped storage hydro, and some steam and combustion turbine units to provide system startup power.

4.5.3.1 Grid Characteristics

To more fully explain grid operation, the following concepts will be discussed: demand, capacity, reserve margin, age of power plants, and constraints on transmission lines.

Demand

Demand is the amount of electricity that the customer requires. The demand for electricity varies with the hour of the day, day of the week, and month of the year due to factors such as area temperature and humidity. When demand is greatest, it is said to "peak". Figure 4.5-4 shows the peak season, months, and percentage by which the peak exceeds the average demand. Capital letters denote major peaks, lower case denotes minor peaks. The percentage by which the peak exceeds the average demand gives insight into the importance of reserve margin in the area. Peak seasonal demand occurs in the summer for most areas of the country and in the winter in others.

To meet expected demand, utilities establish a base load (the amount of electricity they need to produce continuously) and an operating reserve for responding to increased demand. This operating reserve is called spinning or non-spinning reserve and can be loaded up to its limit in ten minutes or less. Spinning reserve is already synchronized to the grid, while non-spinning reserve is capable of being started and loaded within ten minutes. In addition to the spinning and ten minute non-spinning reserve some areas also have thirty minute reserve equipment.

Peak demand is the average or expected peaks estimated by combining such factors as previous use, the number of new customers, and weather forecasts. Demand forecasting is not done on a worst case scenario. It does not anticipate the demand during unusually severe weather or other unforeseeable factors which may affect demand.

An example of severe weather effects on demand (and capacity) occurred on January 18, 1994, in Pennsylvania, New Jersey, and Maryland as well as Delaware, the District of Columbia, and Virginia. The temperature began to drop from approximately 35°F, at 5 a.m. to 8°F, at midnight. Electric demand in the afternoon and evening increased inversely with the temperature when it was expected to drop with the change in usage from commercial to residential. Because the temperature decreased to atypical values, the increase in residential demand exceeded the decrease in commercial demand, peaking at 7:00 p.m., and remained higher than the daytime peaks through midnight of the following day.

Utilities began emergency procedures to reduce demand. Emergencies were declared in Pennsylvania, Maryland, and the District of Columbia. Government offices and many businesses closed early on January 19 and remained closed on January 20. The emergency ended by midday on January 21, though some voltage reductions continued into the evening.

When demand is projected to exceed supply as it did in the January 18, 1994 cold spell, utilities purchase power from adjacent systems. In this case, these systems were also strained by the same cold weather problems; but the New York Power Pool did reduce voltage to its customers and imported power from the New England Power Pool and Canada in order to assist the effected area.

Demand for electricity by nuclear power plants usually occurs when the unit is not producing enough power to supply house loads which may include the safety related systems. Power to start up must also be supplied to the nuclear unit's generator. Offsite power for nuclear plants is not included in the utilities's load management program, but it may be affected by an automatic actuation in response to a grid fault. That is, a nuclear plant's voltage will not be reduced, nor will the plant load shed by the load management schemes; however, grid faults have caused nuclear plants to be isolated from the grid.

Capacity

Capacity is the amount of electricity that the utility can produce or buy. A utility generates electricity by various means: steam turbines, gas turbines, internal combustion engines, jet engines, hydro turbines, and number of other means. Additional electricity may be furnished by co-generation units and non-utility generators. Typically, co-generation units are run by a company that produces the electricity for its own use. Non-utility generators may be co-generators, but are usually power production facilities, built and run by companies which are not regulated utilities. They currently sell the power that they produce to a utility. The Capacity and related data for various areas can be seen on Figure 4.5-5.

Reserve Margin

Reserve margin is the extra electrical capacity that the utility maintains for periods when the demand is unexpectedly high. In mid-afternoon on a hot summer day in July about anywhere in the country, reserve margins are reduced. Utilities must then resort to demand management: urging conservation, reducing voltage (brownouts), and load shedding (rotating blackouts) if additional power cannot be purchased.

The ability to purchase power is limited by the availability and adequacy of transmission lines. Although transmission lines can carry current in excess of rated maximum, attempts to increase the current beyond the setpoint of the protective system would result in the protective system opening the breakers and isolating the lines.

Past events have shown that factors such as unit availability and transmission line capacity affect the adequacy of reserve margin that is actually available for use. Improving unit availability and transmission line reliability are principal methods specified by Councils for maintaining adequate reserve margin. In addition, bringing units under construction on line and purchasing power are viable means of improving reserve margin.

An evaluation of reserve margins around the United States was performed and published in an AEOD draft report entitled "Grid Performance Factors" [AEOD S96-XX, September 1996]. The report showed that different councils use different methods and have dissimilar acceptability levels for reserve margin. Utilities do not all measure adequacy of reserves by the numbers. Evaluations of reserve margin in an AEOD document (Grid Performance Factors) show that one council is not satisfied with its projected 15 to 20 percent reserve margin, another is satisfied with 20 to 25 percent, while another council measures its reserve margin in percentage of peak demand and percentage of the size of the largest unit in its system. From these varying evaluations of adequacy of reserve margin, the following generalizations can be made: the minimum adequate percentage is 15 percent, reserves below 10 percent of total capacity are unacceptably low, and reserves above 25 percent should be more than adequate for any abnormal situation. Low reserves indicate a potential for problems.

Plant Age

With approximately 38 percent of the United States electricity generated by plants 26 years or older, age has the potential to become a factor in grid stability. Many newer plants are large, producing more megawatts from fewer plants. This concentration of generation can lead to stability problems. When the large plant trips, the nearby plants must pick up the load. In addition, the protective schemes at smaller older plants may not be effective in preventing damage to aging plants and thus further affect grid operation. Most of today's distribution system controller equipment, such as mechanical reclosures, require six cycles to react to a line fault which is not fast enough to provide the virtually instantaneous switching needed to keep sensitive equipment operating properly.

Constraints on Transmission Lines

The amount of power on a transmission line is the product of the voltage and the current and a hard to control factor called the "power factor", which is related to the type of loads on the grid. Additional power can be transmitted reliably if there is sufficient available transfer capability on all lines in the system over which the power would flow to accommodate the increase. There are three types of constraints that limit the power transfer capability of the transmission system:

- thermal/current constraints,
- voltage constraints, and
- system operating constraints.

Thermal/Current Constraints

Thermal limitations are the most common constraints that limit the capability of a transmission line, cable, or transformer to carry power. The resistance of transmission lines causes heat to be produced. The actual temperatures occurring in the transmission line equipment depend on the current and ambient weather conditions (temperature, wind speed, and wind direction) because the weather effects the dissipation of the heat into the air. The thermal ratings for transmission lines, however, are usually expressed in terms of current flows, rather than actual temperatures for ease of measurement. Thermal limits are imposed because overheating leads to two possible problems:

- the transmission line loses strength because of overheating which can reduce the expected life of the line, and
- the transmission line expands and sags in the center of each span between the

supporting towers. If the temperature is repeatedly too high, an overheated line will permanently stretch and may cause clearance from the ground to be less than required for safety reasons.

High voltage lines can sag 6 to 8 feet between support towers as they are heated by high current flow and hot weather, and allow flashover between the high voltage line and trees.

Following the August 10, 1996 power outage that affected the western United States, a press release was issued by the Western Systems Coordinating Council on September 25, 1996. The investigation suggests that in all likelihood, the disturbance could have been avoided if contingency plans had been adopted to minimize the effects of an outage of the Keeler-Allston 500 KV line in the Pacific Northwest. In addition, the task force determined that the loss of the McNary generating units and inadequate tree trimming practices, operating studies, and instructions to dispatchers played a significant role in the severity of the event.

Prior to the flash over from the high voltage line to a tree, the interconnected transmission system was knowingly being operated in a manner that was not in compliance with the WSCC reliability criteria. In addition, the loss of the 13 McNary hydroelectric generating units in the northwest was a major factor leading to the outage of the transmission lines (Pacific Intertie) between the Pacific Northwest and California.

Voltage Constraints

Voltage, a pressure like quantity, is a measure of electromotive force necessary to maintain a flow of electricity on a transmission line. Voltage fluctuations can occur due to variations in electricity demand and to failures on transmission or distribution lines. If the maximum is exceeded, short circuits, radio interference, and noise may occur. Also, transformers and other equipment at the substations and/or customer facilities may be damaged or destroyed. Minimum voltage constraints also exist to prevent inadequate operation of equipment. Voltage on a transmission line tends to "drop" from the sending point to the receiving end. The voltage drop along the ac line is almost directly proportional to the reactive power flows and line reactance. The line reactance increases with the length of the line. Capacitors and inductive reactors are installed, as needed, on lines to control the amount of voltage drop. This is important because voltage levels and current levels determine the power that can be delivered to the customers.

On August 11, 1999, the Callaway nuclear plant experienced a repture of a reheater drain tank line. As a result, the plant operators initiated a manual reactor scram, which required offsite power to supply house loads. During this period, the electrical grid had large power flow from the north to south through the switchyard. The power flow, coupled with a high local demand and the loss of the Callaway generator, resulted in switchyard voltage at the site dropping below the minimum requirements for 12 hours. Although offsite power remained available during the transient, the post trip analysis indicated that in the event , 4160 V distribution voltage may have been below the setpoint of the second level undervoltage relays separating the loads from offsite power. Similar events at Callaway and other nuclear power plants identified additional combinations of main generator unavailability, line outages, transformer unavailability, high system demand, unavailability of the local voltage support, and high plant load the could result in inadequate voltages. Common among the events is the inability to predict the inadequate voltage through direct readings of plant switchyard or safety bus voltages, with out also considering grid and plant conditions and their associated analyses.

Operating Constraints

The operating constraints of bulk power systems stem primarily from concerns with security and reliability. These concerns are related to maintaining the power flows in the transmission and distribution lines of a network. Power flow patterns redistribute when demands change, when generation patterns change, or when the transmission or distribution system is altered due to a circuit being switched out of service.

When specific facilities frequently experience disturbances which unduly burden other systems, the owners of the facility are required by their Council to take measures to reduce the frequency of the disturbances, and cooperate with other utilities in taking measures to reduce the effects of such disturbances. The Councils have the right to enforce the agreement made within the Council framework.

On August 13, 1996, the amount of electricity transmitted from the Northwest to power hungry California was cut 25 percent to reduce the chances of another blackout similar to the August 10, 1996 event. The reduction amounted to approximately 1,200 megawatts.

4.5.4 Station Blackout

A station blackout is defined as "the complete loss of alternating current (ac) electric power to the essential and nonessential switchgear buses in a nuclear power plant (i.e. loss of the offsite electric power system concurrent with turbine trip and unavailability of the onsite emergency ac power system)." Because many of the safety systems required for reactor core cooling, decay heat removal, and containment heat removal depend on ac power, the consequences of station blackout could be severe. In 1975, the Reactor Safety Study (WASH-1400) demonstrated that station blackout could be an important contributor to the total risk from nuclear power plant accidents.

This potential increase of risk, combined with increasing indications that onsite emergency power sources (diesel generators in most cases) were experiencing higher than expected failure rates, led the NRC to designate "Station Blackout" as an unresolved safety issue (USI). USI A-44 was established in 1979 and the task action plan that followed concentrated on the analysis of the frequency and duration of loss of offsite power events, and the probability of failure of onsite emergency ac power sources. Other areas of interest included the availability and reliability of decay heat removal systems which are independent of ac power, and the ability to restore offsite power before normal decay heat removal equipment (equipment that relies on ac power) failed due to harsh environment. If the results of the study and analyses demonstrated that the likelihood of a station blackout was significant, then the conclusions would be used as a basis for additional rule making and required design changes as necessary to protect the public health and safety. If safety improvements were indeed necessary, it would be more feasible to identify and initiate improvements with onsite power sources than with either offsite power sources or onsite equipment that required ac power to function. Offsite power source reliability is dependent on several factors such as regional grid stability, potential for severe weather conditions and utility capabilities to restore lost power, all of which are difficult to control. Ultimately, the ability of a plant to withstand a station blackout depends upon the decay heat removal systems, components, instruments, and controls that are independent of ac power. The results of the "Station Blackout" study were published in NUREG-1032.

NUREG-1032 divides loss of offsite power operational experiences into three types:

- plant-centered events which had an impact on the availability of offsite power,
- grid blackouts or perturbations which had an impact on the availability of offsite power, and
- weather-related and other events which had an impact on the availability of offsite power.

4.5.5 Plant Response

The immediate consequences of a station blackout are not severe unless they are accompanied by an accident such as a loss of coolant accident. If the condition continues for a prolonged period, the potential consequences to the plant and public health and safety can be serious. The combination of core damage and containment overpressurization could lead to significant offsite releases of fission products. Any design basis accident in conjunction with a station blackout reduces the time until core damage and release will occur.

Without systems designed to operate independently of ac power, the only way to mitigate the consequences of a station blackout is to take steps to minimize the loss of reactor vessel inventory and quickly restore electrical power to replenish the lost inventory. This will ensure the ability to remove decay heat from the core and prevent fuel damage.
The primary method available to mitigate a station blackout with current plant design features is to initiate a controlled cooldown of the reactor. This evolution is covered in the existing Emergency Procedure Guidelines.

4.5.6 Interim Response by NRC

Interest over loss of all ac power (station blackout) intensified in mid-1980 following license hearings for the operation of the St. Lucie Unit 2 plant in southern Florida. The concern was that with the plant being located in an area subject to periodic severe weather conditions (hurricanes) and questionable grid stability, the probability of a loss of offsite power would be much higher than normal. The Atomic Safety and Licensing Appeal Board (ASLAB) concluded that station blackout should be considered a design basis event for St. Lucie Unit 2. Since the task action plan for USI A-44 was expected to take a considerable amount of time to study the station blackout question, the ASLAB recommended that plants having a station blackout likelihood comparable to that of St. Lucie be required to ensure that they are equipped and their operators are properly trained to cope with the event. NRR changed the construction permit of St. Lucie Unit 2 to include station blackout in the design basis and required Unit 1 to modify its design even though preliminary studies showed that the probability of a station blackout at St. Lucie was not significantly different than for any other plant. Interim steps were taken by NRR to ensure other operating plants were equipped to cope with a station blackout until final recommendations were formulated regarding USI A-44.

Recommendations for improvements to the emergency diesel generators had already been established based on studies of DG reliability (NUREG/CR-0660) and were being implemented for plants currently being licensed. A program for implementing those recommendations at operating reactors was developed, including Technical Specifications improvements. It was recognized that improvements to DG reliability was the most controllable factor affecting the likelihood of a station blackout and could only serve to reduce the probability of occurrence. Generic Letter 81-04 was issued to all operating reactors which required licensees to verify the adequacy of or develop emergency procedures and operator training to better enable plants to cope with a station blackout. Included would be utilization of existing equipment and guidance to expedite restoration of power from either onsite or offsite.

4.5.7 Regulation Changes

Based on information developed following the issuance of USI A-44, a proposed change to NRC regulations and regulatory guidance was published in March 1986 for comment. The rule change consisted of a definition of "station blackout"and changes to 10CFR50.63 which would require that all nuclear power plants be capable of coping with a station blackout for some specified period of time. The time period would be plant specific and would depend on the existing capabilities of the plant as well as a comparison of the individual plant design with factors that have been identified as the main contributors to the risk of core melt resulting from a loss of all ac power. These factors include the redundancy and reliability of onsite emergency ac power sources, frequency of loss of offsite power and the probable time needed to restore offsite power. With the adoption of 10CFR 50.63, all licensees and applicants are required to assess the capability of their plants to cope with a station blackout and have procedures and training in place to mitigate such an event. Plants are also required to cope with a specified minimum duration station blackout selected on a plant specific basis. In addition, Regulatory Guide 1.155 provides guidance on maintaining a high level of reliability for emergency diesel generators, developing procedures and training to restore offsite and onsite emergency ac power and selecting a plant specific minimum duration for station blackout capability to comply with the proposed amendment. A time duration of either 4 or 8 hours would be designated depending on the specific plant design and site related characteristics.

4.5.8 BWR Application

To assess station blackout, BWRs have been divided into two functionally different classes: (1) those that use isolation condensers for decay heat removal but do not have makeup capability independent of ac power (BWR-2 and 3 designs), and (2) those with a reactor core isolation cooling (RCIC) system and either a high pressure coolant injection (HPCI) system or high pressure core spray (HPCS) system with a dedicated diesel, either of which is adequate to remove decay heat from the core and control water inventory in the reactor vessel, independent of ac power (BWR-4, 5, and 6 designs).

The isolation condenser BWR has functional characteristics somewhat like that of a PWR during a station blackout in that normal make up to the reactor is lost along with the residual heat removal (RHR) system. The isolation condenser is essentially a passive system that is actuated by opening a condensate return valve. The isolation condenser transfers decay heat by natural circulation.

The shell side of the condenser is supplied with water from a diesel driven pump. However, replenishment of the existing reservoir of water in the isolation condenser is not required until 1 or 2 hours after actuation. It is also possible to remove decay heat from this type of BWR by depressurizing the primary system and using a special connection from a fire water pump to provide reactor coolant makeup. This alternative would require greater operator involvement. Some BWR-3 designs may have installed a RCIC system, thus providing reactor makeup to the already ac power independent decay heat removal function of the isolation condenser cooling system.

A large source of uncontrolled primary coolant leakage will limit the time the isolation condenser cooling system can be effective. If no source of makeup is provided, the core will eventually become uncovered. A stuck open relief valve or reactor coolant recirculation pump seal leak are potential sources for such leakage. When isolation condenser cooling has been established, the need to maintain the operability of such support systems as compressed air and dc power is less for this type of BWR than it is for a PWR. However, these systems would eventually be needed to recover from the transient.

BWRs can establish decay heat removal by discharging steam to the suppression pool through relief valves and by making up lost coolant to the reactor vessel with RCIC and HPCI or HPCS . In these BWR designs, decay heat is not discharged to the environment, but is stored in the suppression pool. Long term heat removal is by the suppression pool cooling mode of the residual heat removal system. The duration of time that the core can be adequately cooled and covered is determined, in part, by the maximum suppression pool temperature for which successful operation of decay heat removal systems can be ensured during a station blackout event and when ac power is recovered.

At high suppression pool temperatures (around 200 degrees ^{0}F) unstable condensation loads may cause loss of suppression pool integrity. Another suppression pool limitation to be considered is the qualification temperature of the RCIC and HPCI pumps which are used during recirculation. Suppression pool temperatures may also be limited by net positive suction head (NPSH) requirements of the pumps in the systems required to effect recovery once ac power is restored.

All light water reactor designs have the ability to remove decay heat for some period of time. The time depends on the capabilities and availability of support systems such as sources of makeup water, compressed air, and dc power supplies. Also considered is degradation of components as a result of environmental conditions that arise when heating, ventilation and air conditioning (HVAC) systems are not operating. System capabilities and capacities are normally set so the system can provide its safety function during the spectrum of design basis accidents and anticipated operational transients, which does not include station blackout.

Perhaps the most important support system for the plant is the dc power system. During a station blackout, unless special emergency systems are provided, the battery charging capability is lost. Therefore, the capability of the dc system to provide instrumentation and control power can significantly restrict the time that the plant is able to cope with a station blackout. Dc power systems are generally designed to provide specific load carrying capacity in the event of a design basis accident with battery charging unavailable. However, dc system loads required for decay heat removal during a total loss of ac power are somewhat less than the expected design basis accident loads. Therefore, most dc power systems in operation today have the capacity to last longer during a station blackout than during a design basis accident.

Actions necessary to operate systems during a station blackout would not be routine. The operator would have less information and operational flexibility than is normally available during most other transients requiring a reactor cooldown.

In BWRs, the isolation condenser appears to need less operator attention than RCIC and HPCI systems. However, operators would have to insure that automatic depressurization does not occur and that makeup to the isolation condenser is available within approximately 2 hours after the loss of ac power. In BWRs with HPCI or HPCS and RCIC, the operator must control both reactor pressure and level. This may require simultaneous actuation of relief and makeup systems.

4.5.9 Accident Sequence

Figure 4.5-6, taken from NUREG-1032, shows a BWR Mark I containment station blackout accident sequence progression. In this scenario, station blackout occurs at time zero (t_0). The reactor coolant system pressure and level are initially maintained within limits by RCIC and/or HPCI and relief valve actuation. The suppression pool and drywell temperatures begin to rise slowly; the latter is more affected by natural convection heat transport from hot metal (vessel and piping) of the primary system. After 1 hour, because ac power restoration is not expected, the operator begins a controlled depressurization of the primary system to about 100 psi. This causes a reduction in reactor coolant temperature from about 550^{0}F to 350^{0}F, which will reduce the heat load to the drywell as primary system metal components are also cooled. The suppression pool temperature increase is slightly faster than it would have been without depressurization. Drywell pressure is also slowly increasing. At about 6 hours (t_1), dc power supplies are depleted and HPCI and RCIC are no longer operable. Primary coolant heatup follows, which increases pressure and level to the SRV setpoint. Continued core heatup causes release of steam. This eventually depletes primary coolant inventory to the point that the core is uncovered approximately 2 hours after loss of makeup (t_2). Core temperature then begins to rise rapidly, resulting in core melt and vessel penetration within another 2 or 3 hours (t_3). During the core melt phase, containment pressure and temperature rise considerably so that containment failure occurs nearly coincident with vessel penetration, either by loss of electrical penetration integrity (shown at t_4) or by containment overpressure after high pressure core melt ejection, around 11 hours into the accident.

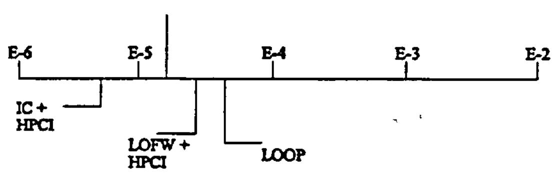
4.5.10 General Containment Information

The BWR Mark I and Mark II containments offer some pressure suppression capability during a station blackout accident, but after a core melt, they may fail by one of two modes. Either mechanical or electrical fixtures in the penetrations will fail because they are not designed for the pressure and temperature that will follow or ultimately, overpressure and subsequent rupture of the containment will occur. Because these containments are generally inerted, hydrogen burn is not considered a likely failure mode. Mark III containments are low pressure, large volume containments, and failure is estimated to result primarily due to overpressurization.

4.5.11 PRA Insights

Plant staff have typically considered the low probability of numerous failures occurring at the same time as an incredible situation. However, the two examples that follow illustrate that multiple failures have existed simultaneously at licensed facilities.

On March 25, 1989, Dresden Unit 3 experienced a loss of offsite power. The plant also lost both divisions of low pressure coolant injection (LPCI), instrument air (IA), and one division of the containment cooling water system for over one hour. In addition, the high pressure coolant injection (HPCI) system failed to start due to a partially completed manual initiation sequence. The isolation condenser (IC) was used to provide core cooling and decay heat removal. Water makeup to the IC was provided by the condensate system. The relative significance of this event (LER 249/89-001) compared with other postulated events at Dresden is indicated in the diagram below:



Where:

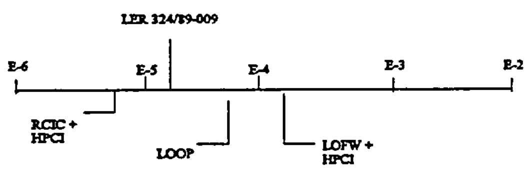
IC	-	isolation condenser
LOFW	-	loss of feedwater
LOOP	-	loss of offsite power

The conditional probability of severe core damage for this event is 1.3X 10 -5. The dominant sequence associated with the event (highlighted on figure 4.5-7), involves simultaneous failures of an SRV to close, HPCI to start, and the operators to depressurize using ADS. Note that the shutdown cooling system for Dresden is separate from LPCI and redundant capability exists for decay heat removal.

On June 17, 1989, Brunswick 2 experienced a loss of offsite power. The control room previously received a ground fault annunciator alarm on the Standby Auxiliary Transformer (SAT) and had called the transmission system maintenance team to initiate repairs. The plant recirculation pumps were being powered from the SAT per procedure to minimize pump seal failure caused by frequent tripping of the recirculation pumps.

The operators had started a planned power reduction when a technician shorted out the transformer, which caused a loss of the SAT and eventually a dual recirculation pump trip. The operator manually scrammed the reactor in accordance with procedures. A dual recirculation pump trip requires the plant to be manually scrammed if the trip results in operation in the region of instability outlined in NRCB 88-07. The plant scram caused a loss of the unit auxiliary transformer and the loss of offsite power. While attempting to place the unit in cold shutdown, the outboard RHR injection valve was discovered stuck in the closed position. It was later determined that the valve disk had separated from the stem.

The conditional probability of severe core damage for this event is 3.6X10-5. The dominant accident sequence (Figure 4.5-8) involves failure to recover offsite power in the short term, coupled with loss of emergency power and battery depletion. It should be noted that if PRA had been considered prior to working on the SAT, the plant staff could have identified that transferring pump power to the unit auxiliary transformer would have been highly beneficial. The relative significance of this event (LER 324/89-009) compared with other postulated events at Brunswick is indicated in the diagram below.



4.5.12 Risk Reduction

The process of developing a probabilistic model of a nuclear power plant involves the combination of many individual events (initiators, hardware failures, operator errors, etc.) into accident sequences and eventually into an estimate of the total frequency of core damage. After development, such models can also be used to assess the importance of individual events. Detailed studies have been analyzed using several event importance measures.

One such measure is the risk reduction importance measure. The risk reduction importance measure is used to assess the change in core damage frequency as a result of setting the probability of an event to zero. Using this measurement, the following individual events at Grand Gulf were found to cause the greatest reduction in core damage frequency if their probabilities were set to zero:

- Loss of offsite power initiating event. The core damage frequency would be reduced by approximately 92 percent.
- Failure to restore offsite power in one hour. The core damage frequency would be reduced by approximately 70 percent.
- Failure to repair hardware faults of diesel generator in one hour. The core damage frequency would be reduced by approximately 46 percent.
- Failure of the diesel generator to start. The core damage frequency would be reduced by approximately 23 to 32 percent.
- Common cause failures to the vital batteries. The core damage frequency would be reduced by approximately 20 percent.

4.5.13 Summary

The electrical transmission infrastructure has been the subject of increasing stress over the past several decades. Electrical power demand continues to increase and is expected to double in the next thirty years. Progressive electric industry deregulation has produced great changes and uncertainty among energy providers. New electrical transmission lines are difficult to site and expensive to build, and with the economics of the electric power industry so uncertain, utilities have been working their systems harder and exploiting their built-in safety margins to meet growing demand and peak loads. The electrical utility industry restructuring associated with deregulation is resulting in the separation of responsibility for transmission systems and the actual power delivery to customers (line companies or distribution companies). Transmission companies are being structured to provide open access to power generators, distribution companies and end users. The distribution company provides the final link between the transmission company and the actual customers.

Station Blackout is one of the largest contributors to core damage frequency at BWRs. At all light water reactors operators have to be prepared to deal with the effects of a loss of and restoration of ac power to plant controls, instrumentation, and equipment. Although loss of all ac power is a remote possibility, it is necessary to address the problem both in training of personnel and equipment design. Extensive studies are being conducted to find ways of better understanding and coping with the effects of a total loss of ac power.

BWRs have such a large number of motor driven injection systems that a loss of electrical power implies loss of injection capability. This is why station blackout is consistently identified by PRAs to be the dominant core melt precursor for BWRs.

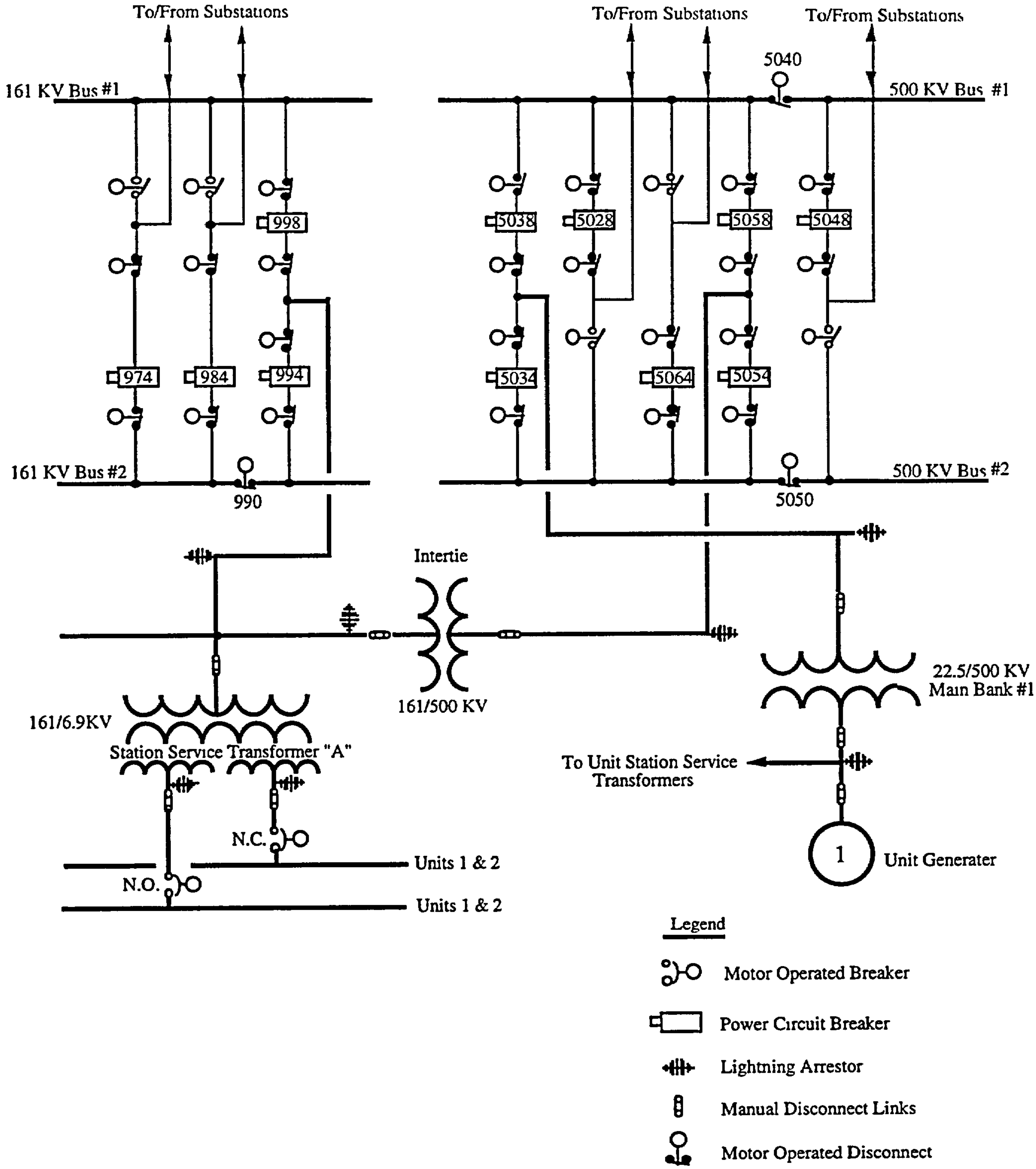


FIGURE 4.5-1 Offsite Power Distribution

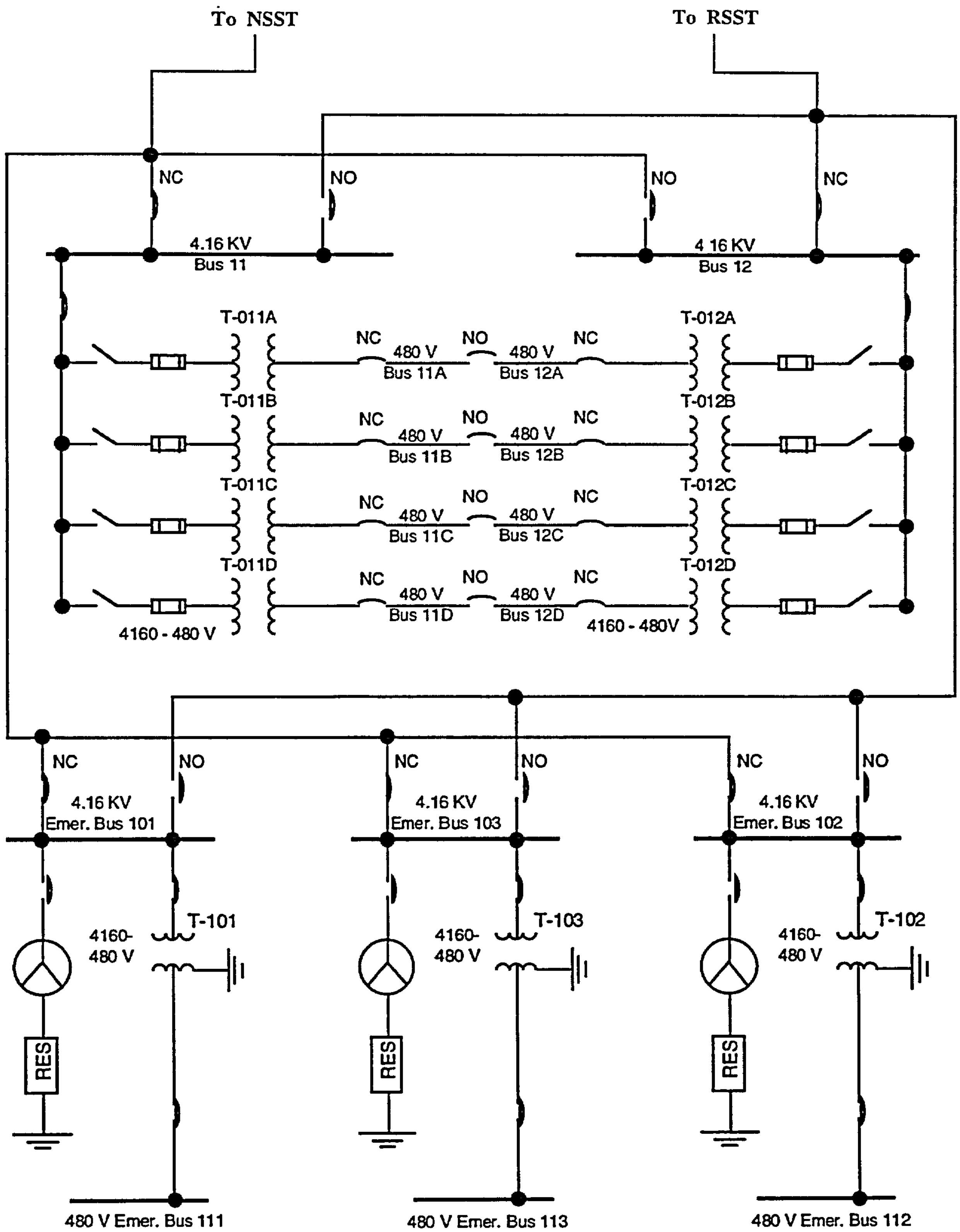
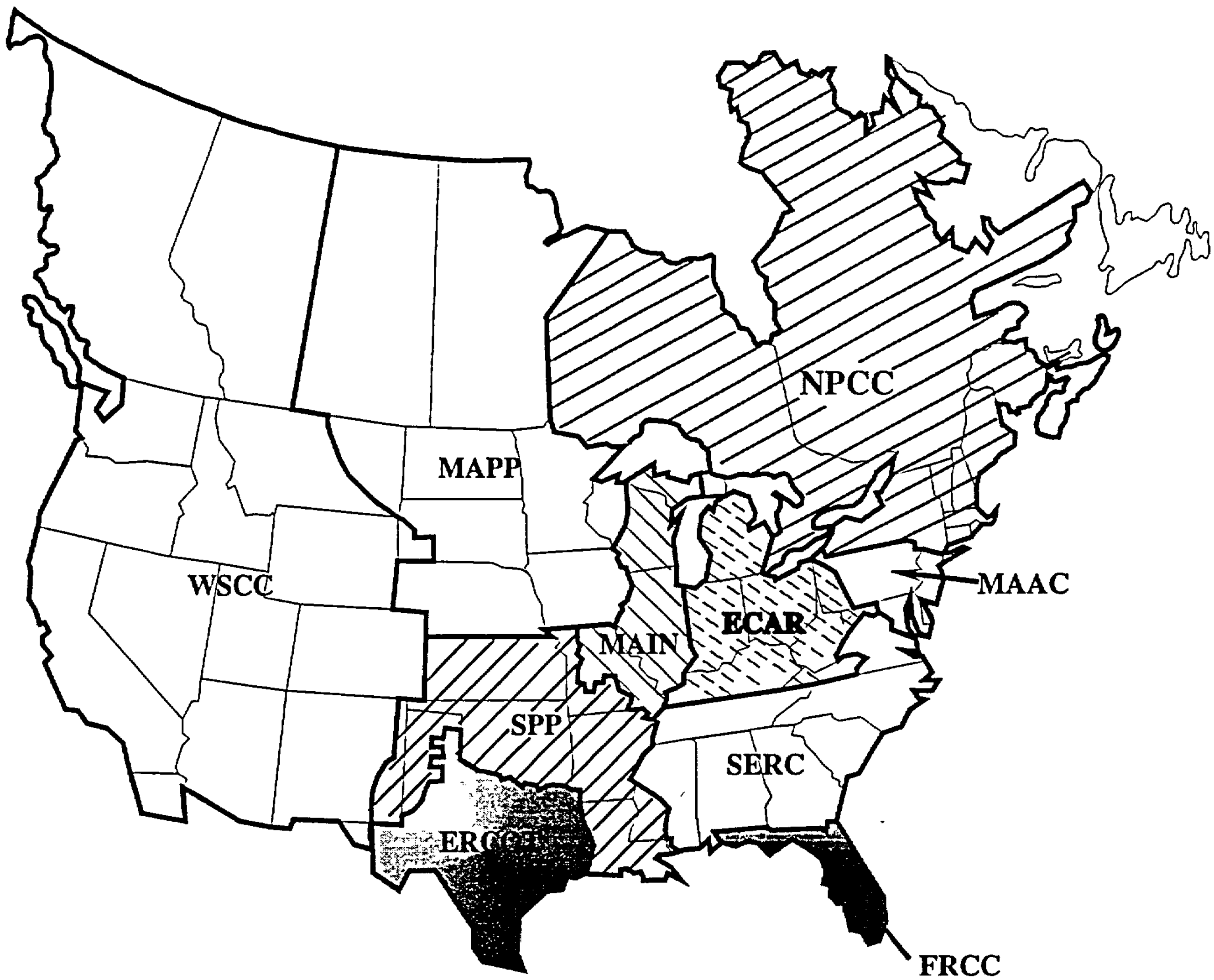


Figure 4.5-2 Emergency AC Power System

0697-4



ECAR - East Central Electric Reliability Coordination Agreement

MAAC - Mid-Atlantic Area Council

MAIN - Mid-America Interpool Network

MAPP - Mid-America Power Pool

NPCC - Northeast Power Coordinating Council

SERC - Southeastern Electric Reliability Council

SPP - Southwest Power Pool

ERCOT - Electric Reliability Council of Texas

WSCC - Western Systems Coordinating Council

FRCC - Florida Reliability Coordinating Council

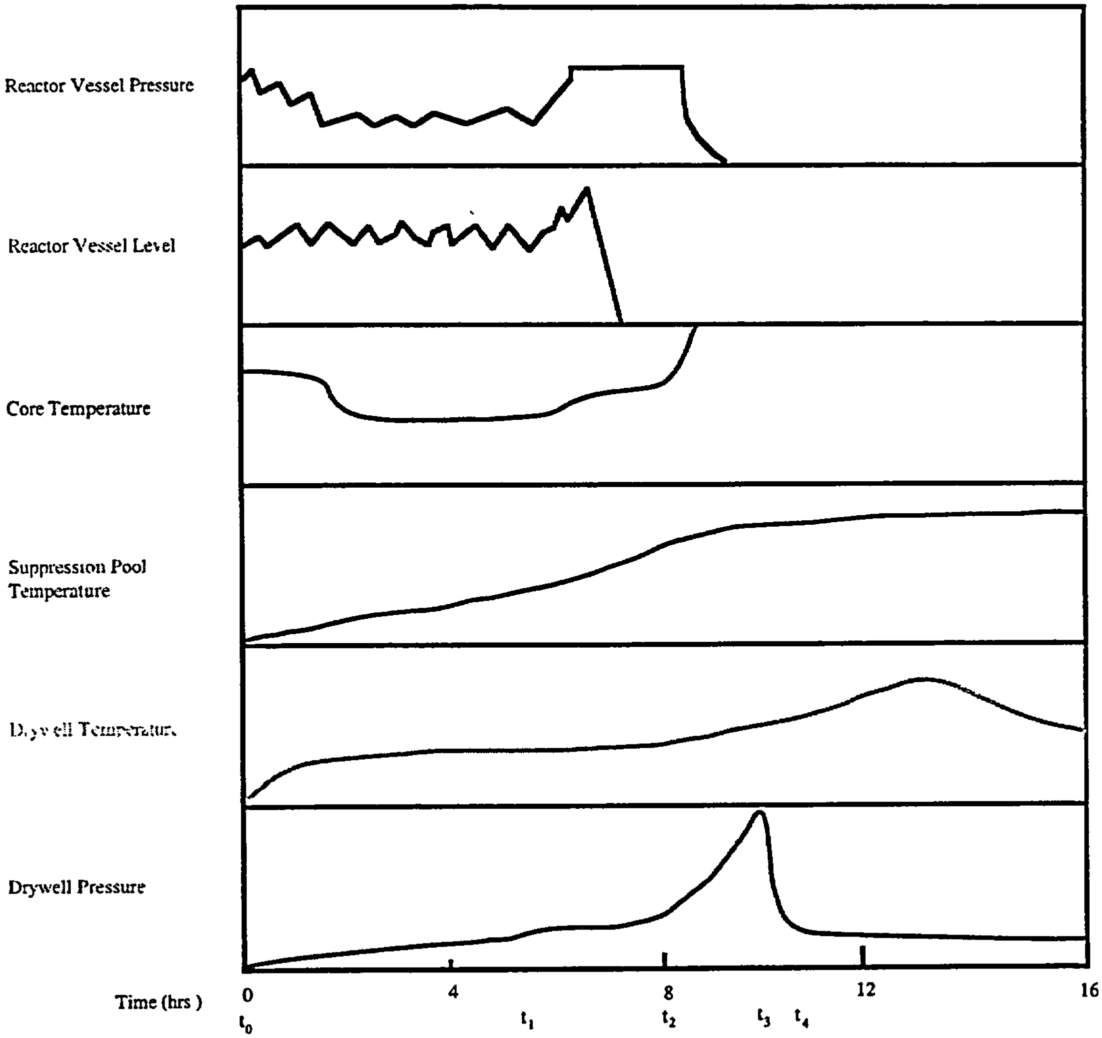
Figure 4.5-3 Member Councils of the North American Reliability Council

Area	PEAK/season	PEAK month	PEAK exceeds Avg. By %
ECAR	SUMMER/winter	JUL-AUG/Jan	13.9
ERCOT	SUMMER	JUN-AUG	22.7
MAAC	SUMMER/winter	JUL/Dec-Jan	25.5
MAIN EMO	SUMMER	JUL/Dec-Jan	25.2
MAIN NIL	SUMMER/winter	JUL-AUG	22.4
MAIN SCI	SUMMER	JUL-AUG/Jan	15.7
MAIN WUM	SUMMER	JUL-AUG	23.2
MAPP	SUMMER/winter	JUL/Dec-Jan	22.9
NPCC NE	SUMMER/winter	AUG/Dec-Jan	12.6
NPCC NY	SUMMER/winter	JUL/Dec-Jan	17.3
SERC FLA	SUMMER/winter	JAN/Jul-Aug	18.2
SERC SOU	SUMMER	JUL-AUG	20.4
SERC TVA	SUMMER/winter	JUL-AUG/Jan-Feb	14.2
SERC VAC	SUMMER/winter	JUL-AUG/Jan	17.9
SPP NOR	SUMMER	JUL-AUG	32.0
SPP SE	SUMMER	AUG	23.3
SPP WCN	SUMMER	JUL-AUG	28.6
WSCC ANM	SUMMER/winter	JUL-AUG/Dec-Jan	24.3
WSCC CSN	SUMMER	JUL-AUG	20.7
WSCC NW	WINTER	DEC-JAN	18.5
WSCC RM	SUMMER/winter	JUL/Dec	10.9

Figure 4.5-4 Peak Seasonal Demand (1991)

Area	Total MW	Prime Mover	Prime Mover MW	Pct. of Total	Nuclear MW	Pct. of Total
ECAR	51487	STEAM	34521	67.0	7639	14.8
ERCOT	55490	STEAM	44750	80.6	4800	8.7
MAAC	55228	STEAM	27595	50.0	12579	22.8
MAIN EMO	8306	STEAM	6109	73.5	1125	13.5
MAIN NIL	21965	NUCLEAR	11294	51.4	11294	51.4
MAIN SCI	9964	STEAM	8612	86.4	930	9.3
MAIN WUM	98.97	STEAM	7052	71.3	1496	15.1
MAPP	38860	STEAM	22052	56.7	3718	9.6
NPCC NE	24431	STEAM	11491	47.0	6343	26.0
NPCC NY	34291	STEAM	17773	51.8	4845	14.1
SERC FLA	33668	STEAM	21892	65.0	3813	11.3
SERC SOU	37834	STEAM	26407	69.8	5607	14.8
SERC TVA	28353	STEAM	14773	52.1	5491	19.4
SERC VAC	50993	STEAM	24847	48.7	14352	28.1
SPP NOR	15783	STEAM	12364	78.3	1145	7.3
SPP SE	28710	STEAM	23122	80.5	4627	16.1
SPP WCN	23604	STEAM	19401	82.2	0	0.0
WSCC ANM	20314	STEAM	11235	55.3	3810	18.8
WSCC CSN	51887	STEAM	22506	43.4	4310	8.3
WSCC NW	49555	HYDRO	33975	68.6	1100	2.2
WSCC RM	9941	STEAM	6390	64.3	0	0.0

Figure 4.5-5 Principal Generation Method (1993)



Time	Sequence of Events
t_0	Loss of all AC power
t_1	DC power (batteries) depleted
t_2	Core uncovery begins
t_3	Reactor vessel penetration
t_4	Containment failure

Figure 4.5-6 BWR Station Blackout Accident Sequence (Mark I Containment, HPCI, and RCIC)

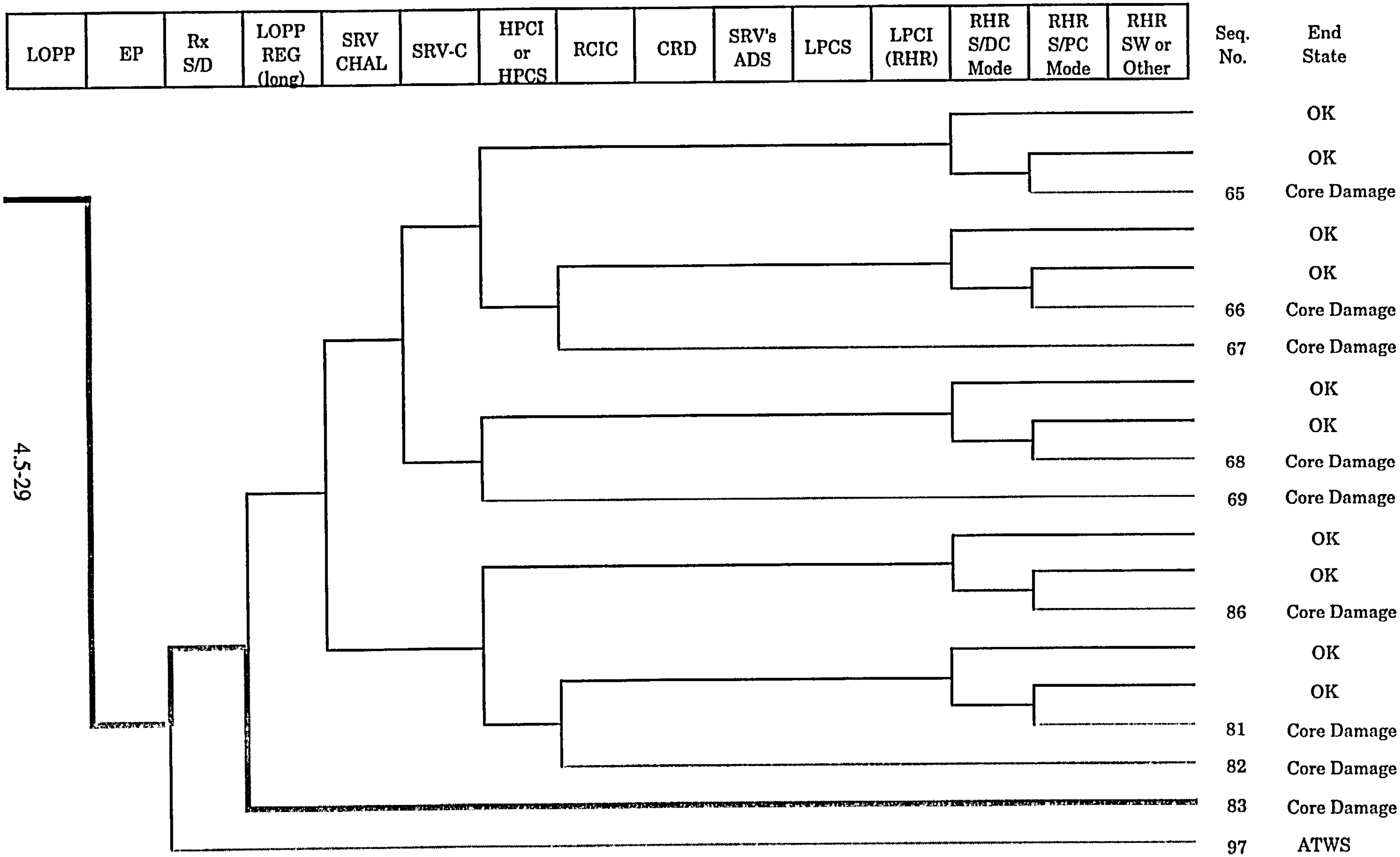


Figure 4.5-8 Dominant Core Damage Sequence for LER 324/89-009

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4.6 AIR SYSTEM PROBLEMS

Learning Objectives:

1. State two safety related functions performed by plant air systems.
2. List two sources of air system contamination.
3. List two causes (other than contamination) of air system failures.

4.6.1 Introduction

Many U.S. Boiling Water Reactor (BWR) plants rely upon air systems to actuate or control safety-related equipment during normal operation. However, at most BWRs, the air systems are not classified as safety systems. Plant safety analyses typically assume that nonsafety-related air systems become inoperable during abnormal transients and accidents, and that the air-operated equipment which is served fails in known, predictable modes. In addition, air-operated equipment which must function during transients or accidents are provided with a backup air (or nitrogen) supply in the form of safety grade accumulators to aid in continued system operation.

On December 3, 1986, 140,000 gallons of radioactive water drained from the spent fuel pool at Hatch 1 and 2 due to deflated pneumatic seals resulting from a mispositioned air line valve.

On December 24, 1986, Carolina Power and Light Company engineers discovered a potential for a common mode failure of all of the emergency diesel generators at Brunswick 1 and 2. They found that HVAC supply dampers for the diesel generator building would fail closed, due to the loss of air, during a loss of offsite power event. The dampers failing closed, reduces the air flow and causes the diesel generator control system to heat up. It was calculated that within one hour the air temperature in the diesel rooms would exceed the environmental qualification temperature of the control system.

On November 25, 1989, Cooper Nuclear Station experienced a closure of the main steam isolation valves which occurred as a result of a total loss of instrument air pressure. An instrument air dryer prefilter pipe ruptured causing low instrument air pressure, which in turn caused the outboard main steam isolation valves to drift closed and some of the control rods to drift into the core.

Consider the following effects the air system has on the Control Rod Drive System. If instrument air is lost, the control rods drift into the core as a result of the scram outlet valves failing open. Control rod drift can cause peaking problems and possible fuel failure even though the rods are moving in the safe direction. Also, oil contamination of the air system has prevented control rods from scramming by preventing the scram solenoid valves from functioning correctly.

4.6.2 Typical Instrument Air System

A simplified diagram of a typical air system is shown in figure 4.6-1. The air system begins with air compressors that take suction from the room in which they are located, raise the pressure of the air to approximately 100 psi, and discharge the air to storage receivers. There are two or more 100% capacity air compressors which are powered from nonvital 480 Vac electrical busses. The compressors are controlled by pressure switches located on the instrument air receivers. During normal operation, one of the air compressors is in service with the redundant compressor in standby. The running compressor loads (compresses air) when the receiver pressure drops below a predetermined value (approximately 95 psi) and unloads when the receiver pressure reaches its normal operating pressure. If instrument air pressure decreases below 95 psi, the standby compressor(s) is/are started. Typically the standby compressor starts between 70 and 80 psi.

The receivers supply the air to instrument and service air headers. Instrument air passes through air dryers and filters prior to supplying various plant components. Dryers remove moisture from the air supply and filters remove foreign particles. The dryers and filters are necessary components because of the materials and small clearances of the internal moving parts of pneumatic equipment. Clean, dry, and oil free air is required for reliable trouble free operation. The air from the conditioning equipment is distributed throughout the instrument air system.

The instrument air system is subdivided by building location, i.e. turbine building, auxiliary building, fuel building, and containment building. The turbine building instrument air supplies components such as the hotwell level control valves, turbine extraction steam and heater drain system, various valve actuators that control cooling water flow to generator hydrogen and oil systems, condensate system demineralizer valves, building heating and air conditioning, and the steam sealing system for the turbines. The reactor building instrument air loads include the outboard main steam isolation valves, control rod drive hydraulic system and various other components. The drywell air supply is use for the inboard main steam isolation valves, and equipment and floor drain isolation valves. The instrument air supply to the drywell is equipped with an automatic isolation valve that closes on a containment isolation signal. Of course, when an isolation occurs, the air supply header inside the containment will depressurize.

The service air system is used to supply air to components such as the demineralizer backwash and precoat system and hose stations for pneumatic tools. Many boiling water reactor plants utilize separate service air systems to meet this need.

4.6.3 Instrument Air System Problem Areas

4.6.3.1 Water Contamination

Although the instrument air dryers are designed to remove water from the air system, moisture is one of the most frequently observed contaminants in the air system. Water droplets entrained in the air can initiate the formation of rust or other corrosion products which block internal passageways of electric to pneumatic converters resulting in sticking and/or binding of moving parts. In addition, water droplets can obstruct the discharge ports on solenoid air pilot valves (CRD hydraulic system), thus reducing their ability to function properly. Furthermore, moisture can cause corrosion of air system internal surfaces as well as the internal surfaces of equipment connected to the air system. Rust and other oxides have caused the exit orifices of pilot valves and other equipment to be totally blocked, resulting in degraded equipment operation or its complete loss. Additionally, rust particles on the inside of the piping/equipment have the potential to be dislodged during severe vibrations which could lead to simultaneous common mode failures of many downstream components.

4.6.3.2 Particulates

Particulate matter has prevented air from venting through discharge orifices of solenoid air pilot valves and valve operators. A clogged orifice changes the bleeddown rate, which affects the valve opening or closing times and could result in complete failure. Additionally, small particles have prevented electrical to pneumatic converters from functioning properly. Air dryer desiccant has been found in air pilot valve seals, preventing the valve from operating correctly.

4.6.3.3 Hydrocarbons

Hydrocarbon contamination of air systems can cause sluggish valve operations as well as complete loss of valve motion. Compressor oil has been observed to leave a gummy-like residue on valve internal components. This causes the valves to operate sluggishly, erratically, or completely fail to operate. Hydrocarbons have also caused valve seals to become brittle and stick to mating surfaces, thereby preventing valve motion. In some cases, parts of deteriorated seals were found in air discharge orifices of valves thus preventing the valve from operating correctly.

4.6.4 Component Failures

Numerous components make up the plant service and instrument air system. The following paragraphs describe a few common failures and possible ramifications.

4.6.4.1 Air Compressors

In most plants, instrument air systems include redundant air compressors, but generally they are not designed as safety-grade or safety-related systems. As a result, a single failure in the electrical power system or the compressor cooling water supply can result in a complete loss of the air compressors. Because plants have redundant air compressors and automatic switching features, single random compressor failures usually do not result in a total loss of air. Most air system compressors are of the oil-less type. However, some plants do use compressors that require oil as a lubricant, and have experienced oil contamination of their air systems. Similarly, the temporary use of oil lubricated backup or emergency compressors without provisions for adequate filtration and drying can result in significant air system degradation.

4.6.4.2 Distribution System

Since most instrument air systems are not designated safety-grade, or safety-related, they are vulnerable to a single distribution system failure. For example, a single branch line or distribution header break could causing partial or complete depressurization of the air system.

4.6.4.3 Dryers and Filters

Single failures in the instrument air filtration or drying equipment can cause widespread air system contamination, resulting in common failures of safety-related equipment. For example, a plugged or broken air filter, a malfunctioning desiccant tower heater timer or plugged refrigerant dryer drain can cause desiccant, dirt or water to enter the air lines. As discussed in section 4.6.3.1, such contaminants could result in significant degradation, or even failure, of important air system components.

4.6.5 Regulatory Issues

4.6.5.1 Safety Issue Definition

Compressed air degradation has the potential to affect multiple trains of safety-related equipment. Air system degradation includes (1) gradual loss of air pressure and (2) air under pressurization or over pressurization outside the design operating pressure range of the associated equipment dependent on the air system. It is not clear what failure modes could result from these types of events. ACRS feels that although unresolved safety issue A-47 addressed sudden complete loss of air pressure, it did not adequately investigate the effects of air system degradation on safety-related equipment.

4.6.5.2 Regulation and Guidance

While no regulations specifically address degradation of instrument air systems, several general design criteria do provide requirements for safety-related structures, systems, and components. General design criterion (GDC) 1 states that structures, systems, and components important to safety must be designed, fabricated, and tested to quality standards commensurate with the importance of safety functions to be performed. GDC 5 requires that shared systems and components important to safety be capable of performing required safety functions.

Guidance provided in standard review plan (SRP) section 9.3.1 "Compressed Air Systems," states that all safety-related air-operated devices that require a source of air to perform safety-related functions be identified and reviewed. This requirement ensures that failure of an air system component or loss of the air source does not negate functioning of a safety-related system.

Guidance for testing of air systems is provided in Regulatory Guide 1.68.3, "Preoperational Operational Testing of Instrument and Control Air Systems". The guide requires tests to determine the response of air-operated or air-powered equipment to sudden and gradual pressure loss, through and including a complete loss of pressure. In addition, response of equipment to partial reductions in system pressure must be tested. Functional testing of instrument /control air systems important to safety should be performed to ensure that credible failures resulting in an increase in the supply pressure will not cause loss of operability. The system must also be able to meet the quality requirements of ANSI/ISA S7.4-1975, "Quality Standard for Instrument Air," with respect to the allowable amounts of oil, water, and particulate matter. If licensees of operating plants make modifications or repairs to their air systems, then their proposed restart testing program will be evaluated according to RG 1.68.3.

In 1988, the NRC issued Generic Letter 88-14, which requests that licensees perform a design and operations verification of their instrument air systems. The verification includes the following:

- Testing actual instrument air quality to ensure it is consistent with the manufacturer's recommendations for individual components served.
- Maintenance practices, emergency procedures, and training are adequate to ensure that safety-related equipment will function as intended on loss of instrument air.
- The design of the entire instrument air system including accumulators is in accordance with its intended function.
- Testing of air-operated safety-related components to verify that those components will perform as expected in accordance with all design basis events.

Generic Letter 88-14 does not address verification of the operation of safety-related component failure during gradual increasing or decreasing pressure.

4.6.5.3 NRC and Industry Programs

The NRC has issued several IE notices that address compressed air system-related failures that have occurred at several nuclear plants. IE Notice 81-38, "Potential Significant Equipment Failures Resulting From Contamination of Air-Operated Systems," reported the potential for air- operated systems to fail because of oil, water, desiccant, and rust contamination. IE Notice 82-25, "Failures of Hiller Actuators on Gradual Loss of Air Pressure," reported the failure of valves to move to a specified position on loss of air pressure. The actuators were depressurized gradually, rather than suddenly, resulting in the failure of the valves to move to their fail-safe position. IE Notice 88-24, "Failures of Air-Operated Valves Affecting Safety-Related Systems," reported failure of safety-related valves to assume their fail-safe positions upon deenergization of their respective solenoid valves. In this event, the maximum operating pressure differential for the valves was less than the operating pressure for the air system. In addition to the IE notices, the NRC created Generic Issue 43, " Reliability of Air Systems," and assigned it a high priority for evaluation. In a 1989 letter from ACRS to the NRC, ACRS stated that in light of the requirements of Generic Letter 88-14, they did not consider the resolution of Generic issue 43 adequate. In response, the NRC recommended that air system degradation be addressed as a separate issue.

4.6.5.4 Operating Experience

In 1987, AEOD completed a comprehensive review and evaluation of the potential safety implications associated with air system problems. This report identified the following specific deficiencies:

- The air quality capability of the instrument air filters and dryers does not always match the design requirements of the equipment using the air.
- Maintenance of instrument air systems is not always performed in accordance with manufacturer's recommendations.
- The air quality is usually not periodically monitored.
- Plant personnel frequently do not understand the potential consequences of degraded air systems.
- Operators are not well trained to respond to losses of instrument air, and the EOPs for such events are frequently inadequate.
- At many plants the response of key equipment to a loss of instrument air has not been verified to be consistent with the FSAR.
- Safety-related backup accumulators do not necessarily undergo surveillance testing or monitoring to confirm their readiness.
- The size and the seismic capability of safety-related backup accumulators at several plants have been found to be inadequate.

Design deficiencies were identified as the root causes of most air system problems. With the introduction of Individual Plant Examinations (PRA) and accident management requirements by the commission, these deficiencies can be discovered and corrected.

Shortly after the PRA program (April 1988) was begun at Fermi 2, a question arose concerning the safety impact resulting from operating the non-interruptible air system cross connected (division 1 with division 2). An analysis of the effects on core damage frequency showed that the risk from scenarios involving a transient and a loss of air could be reduced by a factor of 2 if the non-interruptible air system was operated cross connected.

4.6.6 Summary and Conclusion

Losses of instrument air have occurred in the industry. Failure of equipment and systems due to air system degradation discussed above have not been included in the plant safety analyses. Consequently, some plants with significant instrument air system degradation may be operating or may have operated with a much higher risk than previously estimated. Many plants do not have specific license requirements prohibiting operation with degraded air systems. Therefore, high confidence does not exist that all plants will voluntarily take corrective action to avoid plant operation with degraded air systems.

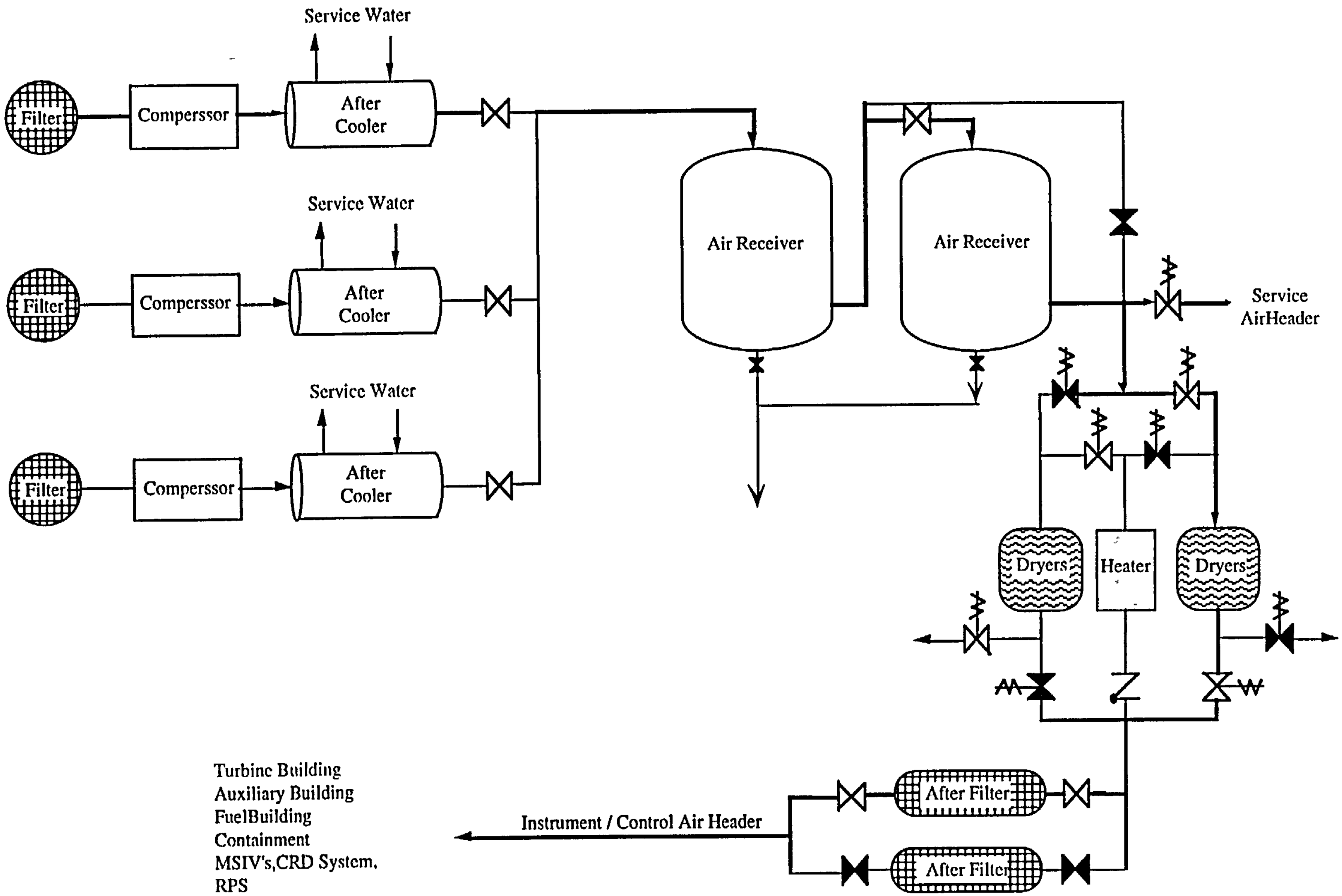

Figure 4.6-1 Typical Air System

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4.7 INTERFACING SYSTEM LOCA

Learning Objectives :

1. Define the term "interfacing system LOCA (ISL)"
2. List the major interfacing lines for a BWR.
3. Explain why an interfacing system LOCA is a safety concern.

4.7.1 Introduction

The term "interfacing system LOCA" (ISL) refers to a class of nuclear plant loss of coolant accidents in which the reactor coolant system pressure boundary interfacing with a support system of lower design pressure is breached. This could cause an over pressurization and breach the support system, portions of which are located outside of the primary containment. Thus, a direct and unisolable coolant discharge path would be established between the reactor coolant system and the environment. Depending on the configuration and accident sequence, the emergency core cooling systems as well as other injection paths may fail, resulting in a core melt with primary containment bypassed.

The Reactor Safety Study, WASH-1400, identified an interfacing system LOCA accident in a PWR as a significant contributor to risk from the core melt accidents (event V). The event V arrangements were defined to be two check valves in series or two check valves in series with an open motor operated valve. Such valve arrangements are commonly used in PWRs but rarely in BWRs.

As a result of the WASH-1400 study and the TMI-2 accident, all light water reactors with operating license granted on or before February 23, 1980 were required to periodically test or continuously monitor the event V valves. The periodic test consisted of in-service leak rate testing of each check valve every time the plant is shutdown and/or each time either check valve is moved from the fully closed position.

Since early 1981, the Office of Nuclear Reactor Regulation (NRR) staff commenced back fitting operating reactors by requiring in-service leak rate testing of all pressure isolation valves that connect the reactor coolant system to lower pressure systems. On April 20, 1981, orders were sent to 32 PWRs and 2 BWRs which required leak rate testing of Event V valves.

In February 1985, the NRR staff established new acceptance criteria for leak rate testing. The leak rate of each valve must be no greater than one half gallon per minute for each nominal inch of valve size and no more than 5 gallons per minute for any particular valve.

The current leak rate testing requirements for pressure isolation valves on BWRs are as follows:

- At least once per 18 months.
- Prior to returning the valve to service following maintenance or replacement work.

Recent BWR operating experience indicates that pressure isolation valves may not adequately protect against over pressurization of low pressure systems. The over pressurization may result in the rupture of the low pressure piping. This event, if combined with failures in the emergency core cooling systems and other systems that may be used to provide makeup to the reactor coolant system, would result in a core melt accident with an energetic release outside the containment.

4.7.2 Interfacing Lines

The major interfacing lines discussed in the following sections include:

- LPCI injection lines
- shutdown cooling suction line
- shutdown cooling return line
- steam condensing supply lines to RHR heat exchanger
- reactor vessel head spray line
- high pressure core spray suction
- low pressure core spray line

4.7.2.1 LPCI Injection Line

The RHR system consists of two loops, (A & B). Each loop contains two pumps, associated valves; and piping to inject water from the suppression pool to the reactor vessel. Both loops A and B are used for multiple purposes (modes), such as shutdown cooling mode, steam condensing mode, containment spray mode, and suppression pool cooling mode.

Failure of a LPCI injection testable check valve and/or the normally closed injection valve would over pressurize the RHR system piping and cause failure of that loop. The relief valve located between the inboard and outboard injection valves has a capacity of approximately 185 gpm and a set pressure of 500 psig. The relief valve is capable of handling the flow from the testable check valve bypass valve, but not the amount of flow that would result from a failure of the testable check valve to close.

4.7.2.2 Shutdown Cooling Suction Line

The suction line from recirculation loop B contains an inboard and outboard isolation valve and an individual pump isolation valve. The containment isolation valves automatically close if reactor vessel reaches level 3 or reactor pressure increases to 135 psig. Failure of the containment isolation valves to close would allow the low pressure piping to fail causing an interfacing system LOCA.

4.7.2.3 Steam Condensing Supply Lines to RHR Heat Exchanger

The steam condensing mode of the RHR system can be manually placed in service following a reactor trip and would be capable of condensing all of the steam generated within 1.5 hours following the trip. The steam is removed via the HPCI steam line outside of the drywell and directed to the RHR heat exchanger where it is condensed. The condensate is then returned to the suction line of the RCIC or the suppression pool depending on the water quality.

Each RHR heat exchanger shell is protected against over pressure by a relief valve located on the steam inlet piping. Each relief valve is set at 500 psig and is sized to limit pressure to 550 psig with the steam pressure control valve fully open and steam pressure equal to the lowest SRV setpoint (1103 psig).

4.7.2.4 Reactor Vessel Head Spray

The vessel head spray line is used during the shutdown cooling mode of operation to cool the upper vessel area prior to flood-up of the vessel. If the isolation check valves and the motor operated isolation valves fail, the low pressure RHR system LPCI line will be over pressurized.

The result is identical to paragraph 4.7.2.1 mentioned above. Therefore, the same indications will be available to the operators.

4.7.2.5 Low Pressure Core Spray Injection Line

Failure of the LPCS testable check valve and/or the normally closed injection valve would over pressurize the LPCS piping and possibly causes a rupture. The relief valve lifts automatically at a set pressure of 586 psig and has the same design requirements as the RHR injection line relief valve.

4.7.2.6 High Pressure Core Spray Suction

The HPCS system starts automatically on level 2 or high drywell pressure. Upon actuation, the normally open suction valve from the condensate storage tank is signaled to open, the test return valves are signaled to close, and the normally closed injection valve is signaled to open. Subsequently, the injection valve receives an automatic close signal when vessel level reaches level 8 thus the pump will continue running with flow through the minimum flow line. If the minimum flow valve fails closed and the water leg pump discharge stop check valve fails open, there is a chance of over pressurizing the low pressure suction piping.

4.7.3 Operating Experiences

With two series check valves the probability of at least one of the check valves being seated and not leaking would be extremely high. In addition, if leakage were to occur to the point of causing a LOCA in the low pressure piping, the high differential pressure across the valve should cause the valves to seat, which would terminate the accident. However, actual operating experiences indicates that both check valves have failed to properly close.

The Nuclear Power Experiences Manual reports that between 1974 and 1978 there were nine dilution events in the cold leg accumulators of PWR plants. The following sections discuss other events that pertain to BWRs and interfacing system LOCAs.

4.7.3.1 Cooper Nuclear Station

The HPCI testable check valve failed to remain fully closed due to a broken sample probe wedged under the edge of the valve disc. The origin of the sample probe was traced to the feedwater system. The failure was not recognized until backflow of feedwater to the HPCI pump suction occurred.

4.7.3.2 LaSalle event on October 5, 1982

A testable check valve was tested with the plant at 20% power. The test was accomplished by opening the check valve bypass valve to equalize pressure across the check valve disc and then opening the check valve from the control room. Following the test, both the bypass valve and the testable check valve failed to reclose.

4.7.3.3 Pilgrim event on February 12, 1986 and April 11, 1986

On February 12, both the testable check valve and the normally closed LPCI outboard injection valve leaked, resulting in frequent high pressure alarms. These alarms occurred repeatedly for approximately two weeks prior to this event. Operators simply vented the piping after each alarm. On this date, the outboard injection valve was manually closed and its closing torque switch replaced. The plant continued operation until April 11, at which time, more high pressure alarms occurred. It was discovered that the outboard injection valve started leaking again and subsequently required a plant shutdown to facilitate repairs.

4.7.3.4 Dresden Unit 2 Event

On February 21, 1989, with Dresden Unit 2 operating at power, temperature was greater than normal in the HPCI pump and turbine room. The abnormal heat load was caused by feedwater leaking through uninsulated HPCI piping to the condensate storage tank. During power operation, feedwater temperature is less than 350°F, and feedwater pressure is approximately 1025 psi. Normally, leakage to the condensate storage tank is prevented by the injection check valve, the injection valve, or the discharge valve on the auxiliary cooling water pump.

On October 23, 1989, with the reactor at power, leakage had increased sufficiently to raise the temperature between the injection valve and the HPCI pump discharge valve to 275°F and at the discharge of the HPCI pump to 246°F. Pressure in the HPCI piping was 47 psia. On the basis of the temperature gradient and the pressure in the piping, the licensee concluded that feedwater leaking through the injection valve was flashing and displacing some of the water in the piping with steam. This conclusion was confirmed by closing the pump discharge valve (M034) and monitoring the temperature of the piping. As expected, the pipe temperature decreased to ambient.

The event at Dresden is significant because the potential existed for water hammer or thermal stratification to cause failure of the HPCI piping and for steam binding to cause failure of the HPCI pump. Further, failure of HPCI piping downstream from the injection valves would cause loss of one of two feedwater pipes.

The licensee had not heard the noise that is usually associated with water hammers. Never the less, loosening of pipe supports, damage to concrete surfaces, and the pressure of steam in the piping strongly indicated that water hammers had occurred in the HPCI system, probably during HPCI pump tests or valve manipulations.

4.7.4 PRA Insight

NUREG/CR-5928, ISLOCA Research Program, primary purpose is to assess the ISLOCA *risk* for BWR and PWR plants. Previous reports (NUREG/CR-5604, 5745, and 5744) have documented the results of ISLOCA evaluations of three PWRs and to complete the picture a BWR plant was examined. One objective of the Research Program is identification of generic insights. Toward this end a BWR plant was chosen that would be representative of a large percentage of BWRs.

The reference BWR plant used as the subject of ISLOCA analysis was a BWR/4 with a Mark-I containment. Power rating for the plant is 3293 MWt. BWRs of similar design include:

- Brown's Ferry 1,2, & 3
- Peach Bottom 2 & 3
- Enrico Fermi
- Hope Creek
- Susquehanna 1 & 2
- Limeric 1 & 2

NUREG/CR-5928 document describes an evaluation performed on the reference BWR from the perspective of estimating or bounding the potential *risk* associated with ISLOCAs. A value of 1 x 10^{-8} per year was used as the cutoff for further consideration of ISLOCA sequences.

A survey of all containment penetrations was performed to identify possible situations in which as ISLOCA could occur. The approach taken began with an inventory of these penetrations to compile a list of interfacing systems. Once the list was complete, the design information for each system was reviewed to determine the potential for a rupture given that an over pressure had occurred. The systems included:

- reactor core isolation cooling system
- high pressure coolant injection system
- core spray system
- residual heat removal system
- reactor water cleanup system
- control rod drive system

The results of NUREG/CR-5928 concluded that ISLOCA was not a risk for the BWR plant analyzed. Although portions of the interfacing systems are susceptible to rupture if exposed to full RPV pressure, these are typically pump suction lines that are protected by multiple valves.

4.7.5 Summary

In order to reduce the probability of this type of event even further, license changes have been made to the technical specifications that limit the maximum leak rate through isolation valves.

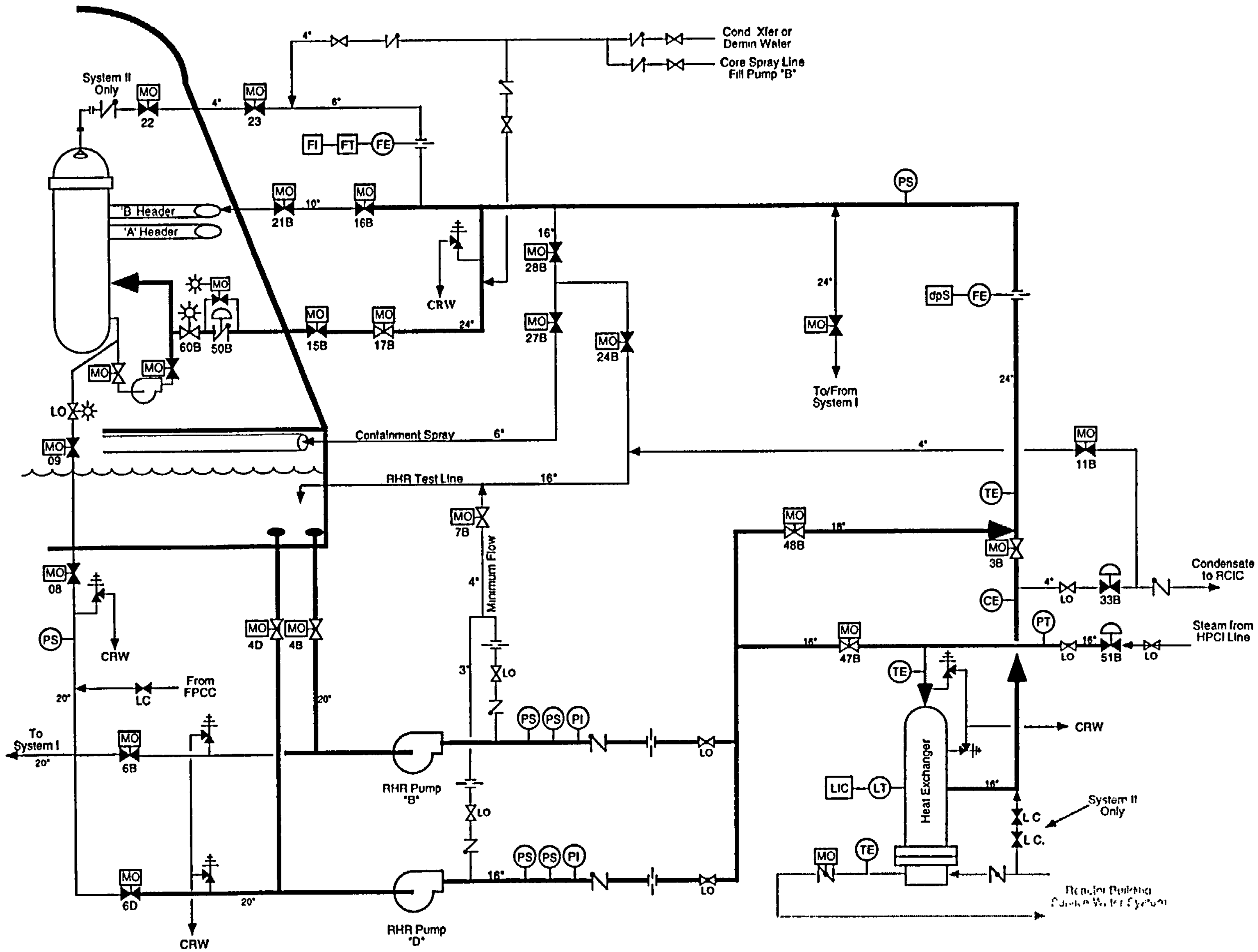

Figure 4.7-1 RHR System LPCI Mode

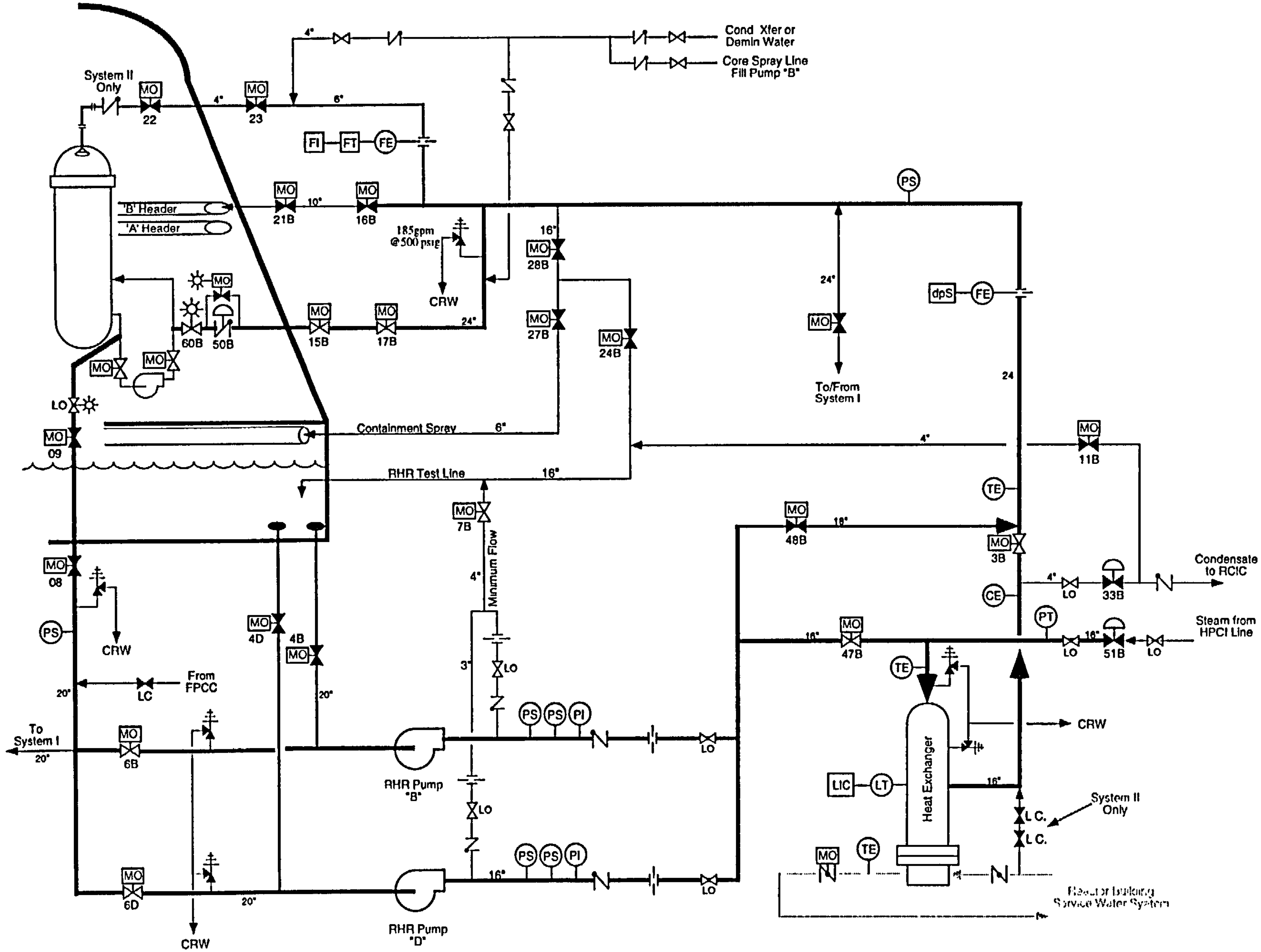

Figure 4.7-2 RHR System Shutdown Cooling Mode

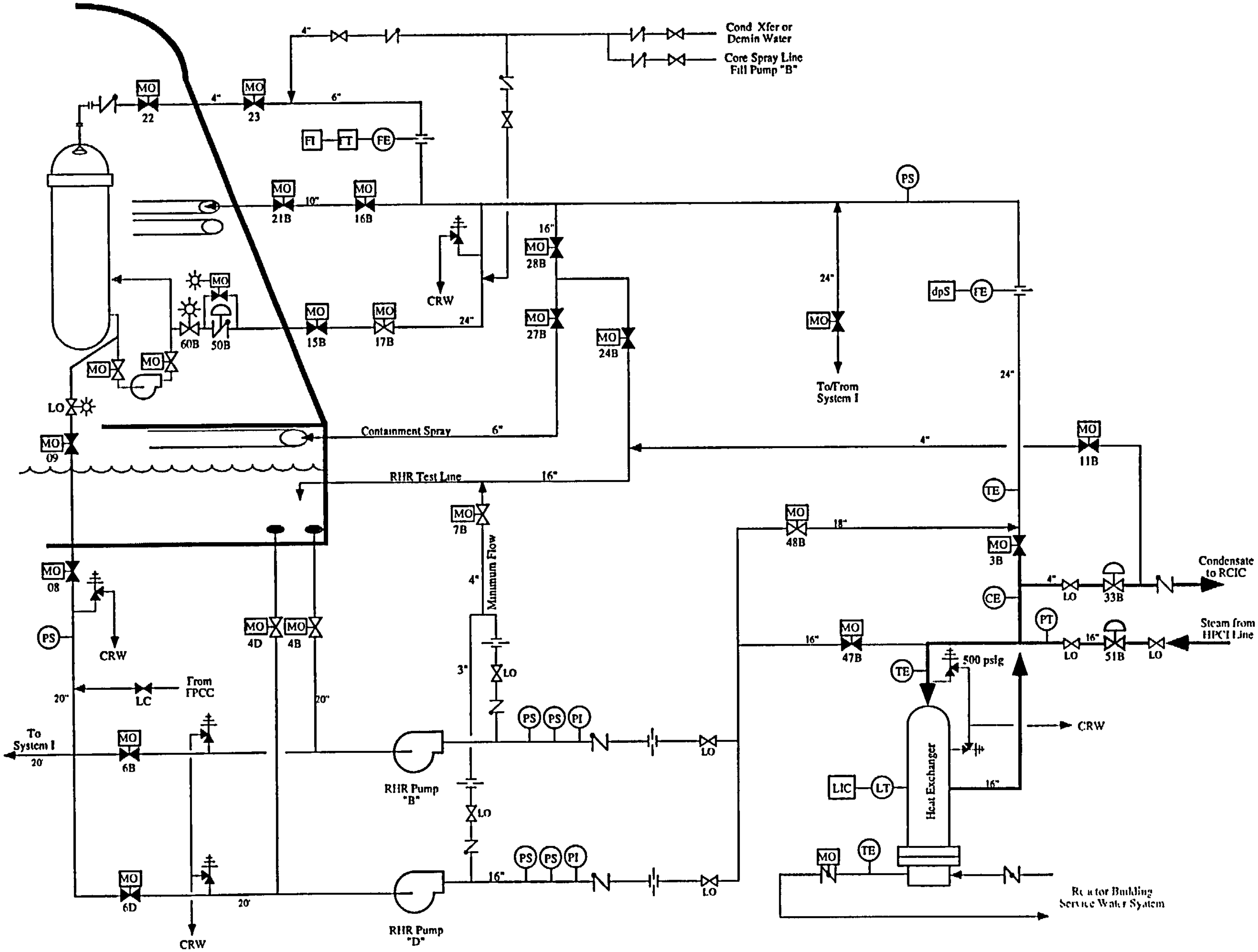

Figure 4.7-3 RHR System Steam Condensing Mode

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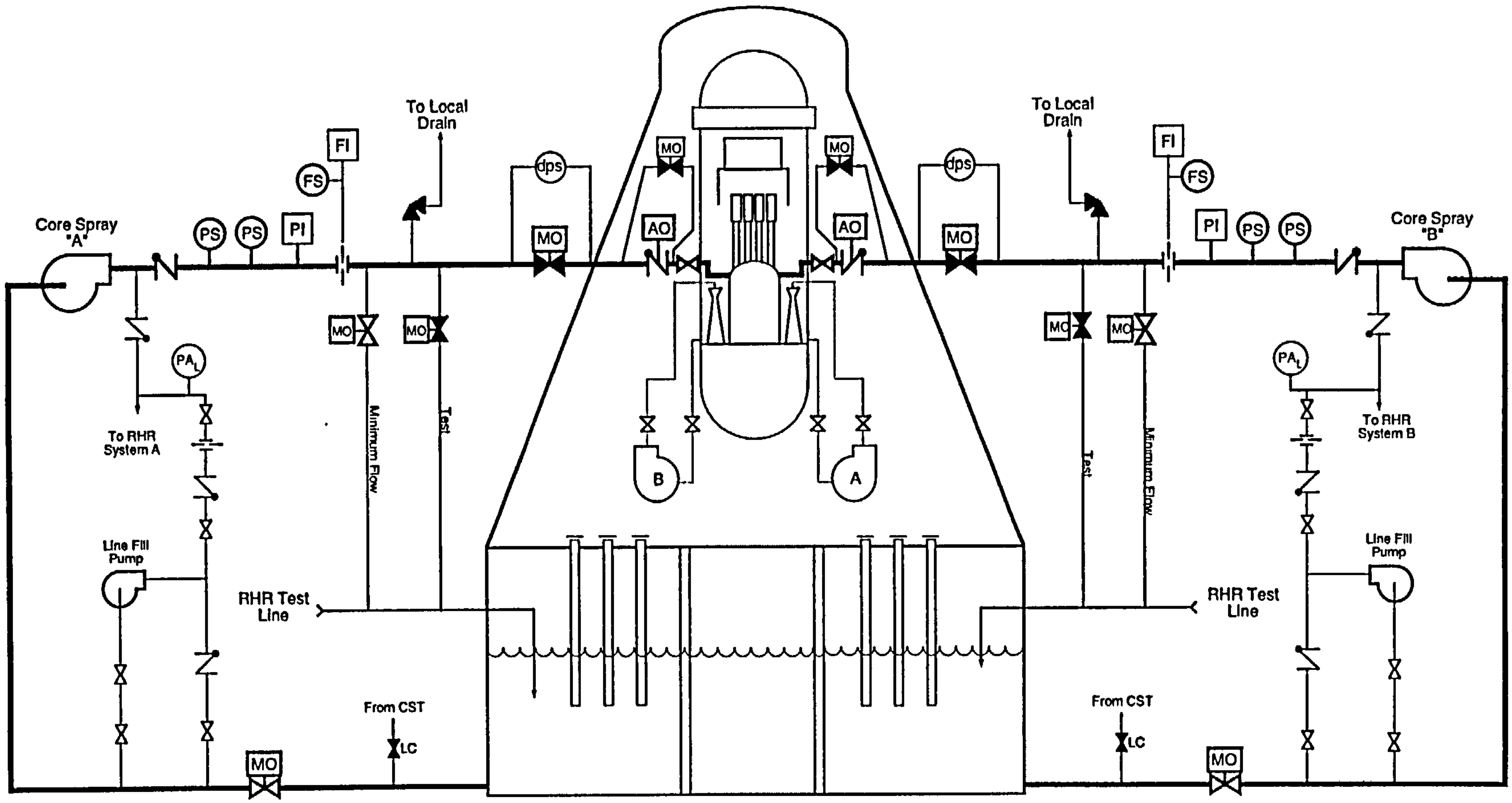

Figure 4.7-4 Core Spray Systems

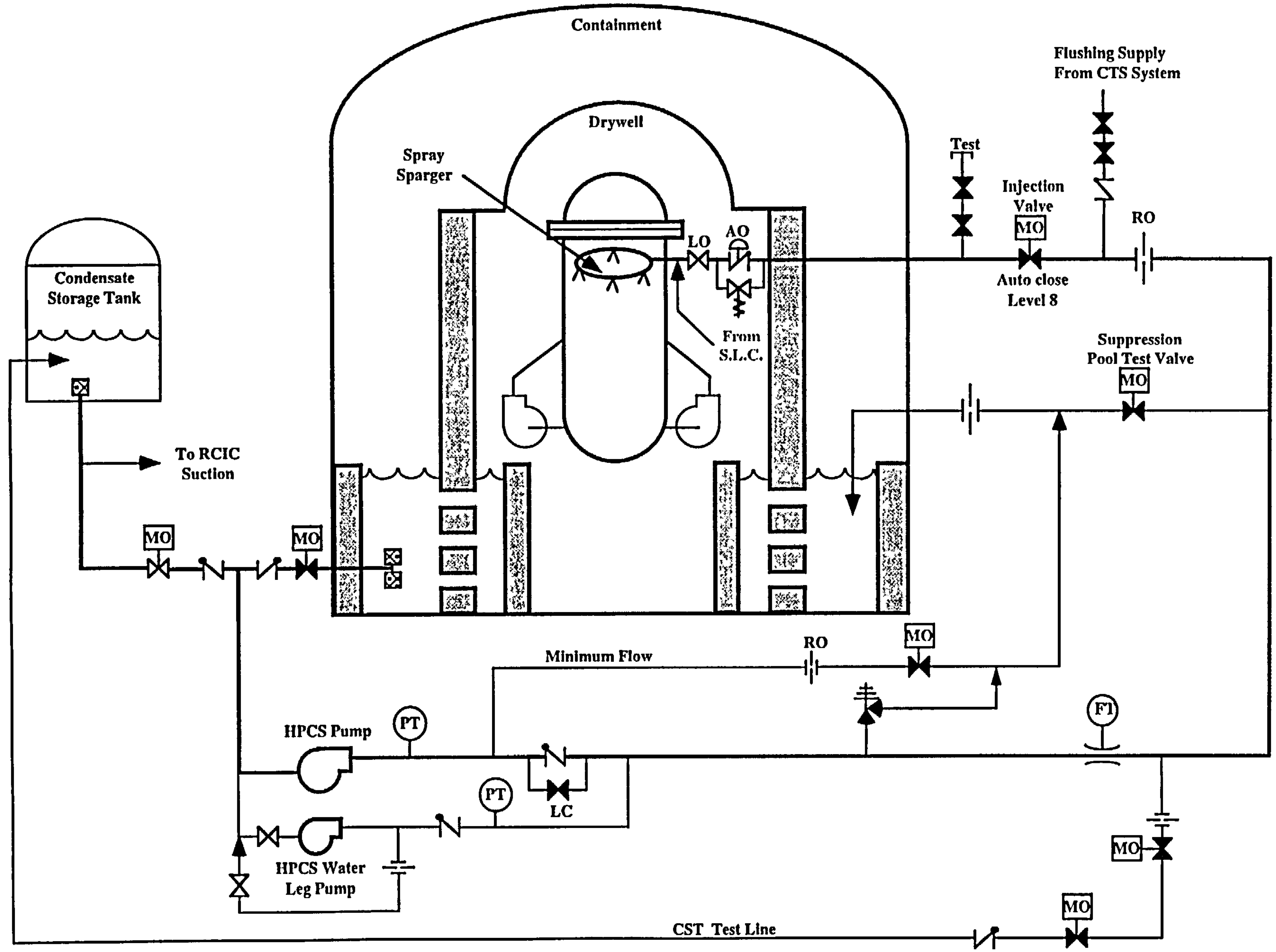

FIGURE 4.7-5 HIGH PRESSURE CORE SPRAY

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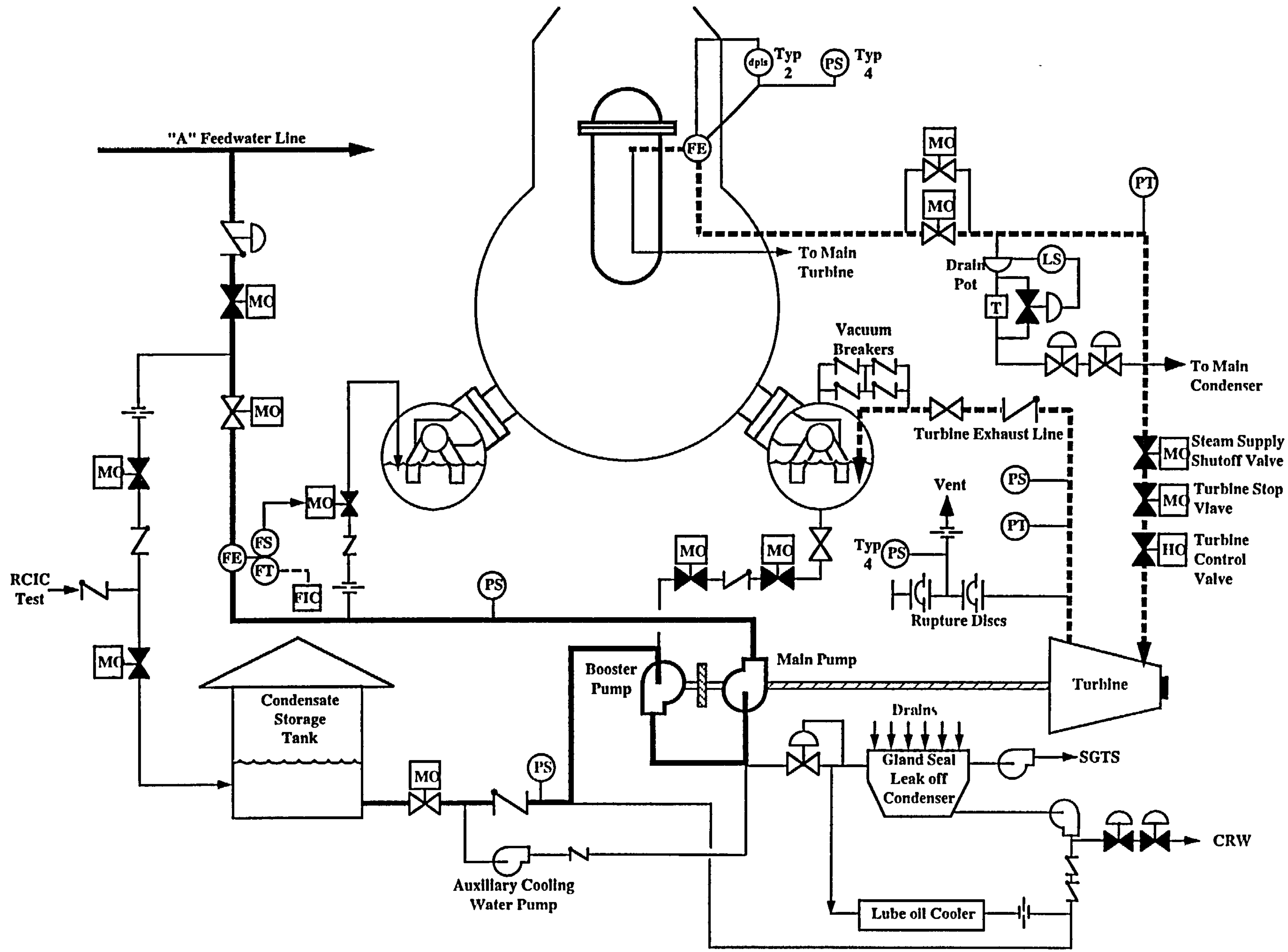

FIGURE 4.7-6 DRESDEN HIGH PRESSURE COOLANT INJECTION SYSTEM

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4.8 Service Water System Problems

Learning Objectives:

1. State three safety related functions performed by most service water systems.

2. List the most frequently observed cause of system degradation, other than system fouling.

3. List three fouling mechanisms that can lead to system degradation

4.8.1 Introduction

Because the characteristics of the service water system may be unique to each facility, the service water system is defined as the system or systems that transfer heat from the safety-related structures, systems, or components to the ultimate heat sink (UHS). Attached are selected service water systems of operating plants, to illustrate some of the differences found in the industry.

The service water system provides cooling water to selected safety equipment during a loss of offsite power. Failure of the service water system would quickly fail operating diesel generators and potentially fail the low pressure emergency core cooling pumps due to the loss of pump cooling or room coolers. The High Pressure Coolant Injection and Reactor Core Isolation Cooling pumps would fail upon loss of their room cooling.

There is an outstanding issue regarding the need for service water that involves the issue of the core spray and residual heat removal pumps requiring service water cooling. One utility (PECo) has stated that these pumps are designed to operate with working fluid temperatures approaching 160°F without pump cooling. However, because it is uncertain whether the suppression pool water temperature can be maintained below 160°F in some core damage PRA sequences the analyses still assume failure of the low pressure emergency core cooling pumps.

The NRC staff has been studying the problems associated with service water cooling systems for a number of years. At Arkansas Nuclear Plant, Unit 2, on September 3, 1980, the licensee shut down the plant when the resident inspector discovered that the service water flow rate through the containment cooling units did not meet the technical specification requirement. The licensee determined the cause to be extensive flow blockage by Asiatic clams (Corbicula species, a non-native fresh water bivalve mollusk). Prompted by this event and after determining that it represented a generic problem of safety significance, the NRC issued Bulletin No. 81-03, "Flow Blockage of Cooling Water to Safety System Components by Asiatic Clam."

After issuance of Bulletin No. 81-03, one event at San Onofre Unit 1 and two events at the Brunswick station indicated that conditions not explicitly discussed in the bulletin can occur and cause loss of heat transfer to the UHS. These conditions include:

- Flow blockage by debris from shellfish other than Asiatic clams and mussel.

- Flow blockage in heat exchanger causing high pressure drops that can deform baffles and allow flow to bypass heat exchanger tubes.

- A change in operating conditions, such as a change from power operation to a lengthy outage, that permits a buildup of biofouling organisms.

- Degradation of cooling water systems due to icing.

- Injection of sealant into intake bays.

By March 1982, several reports of serious fouling events caused by mud, silt, corrosion products, or aquatic bivalve organisms in open-cycle service water systems had been received. These events led to plant shutdowns, reduced power operation for repairs and modifications, and degraded modes of operation. This situation forced the NRC to establish Generic Issue 51, "Improving the Reliability of Open-cycle Service Water Systems." To resolve this issue, the NRC initiated a research program to compare alternative surveillance and control programs to minimize the effects of fouling and increase plant safety.

June 12, 1996 the NRC issued Information Notice 96-36 to alert addressees to potential degradation of facility water intake systems due to icing conditions. This information notice was prompted by events at FitzPatrick (February 25, 1993), Wolf Creek (January 30, 1996), and Fermi (February 5, 1996). Frazil icing is a phenomena that effects the operation of intake structures in regions that experience cold weather. The accumulation of frazil ice on intake trash rakes can completely block the flow of water in the bays. The process starts when the water flowing into the intake is supercooled (water below the freezing point).

Supercooling occurs with a loss of heat from a large surface area such as a lake with open water and clear nights. High winds contribute to the problem by providing mixing of the supercooled water to depths as great as 6 to 9 meters. The frazil ice, which is composed of very small crystals with little buoyancy, is carried along in the water and mixed all through the supercooled water.

Drawing the supercooled water and the suspended frazil ice crystals through an intake structure brings the frazil ice crystals in contact with the trash rake bars. These ice crystals easily adhere to any object with which they collide. Ice collects first on the upstream side of the trash rakes, then steadily grows until the space betweer the trash takes is bridged. The accumulation of ice can withstand high differential pressures, effectively damming the intake bay(s).

4.8.2 AEOD Case Study

The Office for Analysis and Evaluation of Operational Data (AEOD) initiated a systematic and comprehensive review and evaluation of service water system failures and degradation at light water reactors from 1980 to early 1987. The results of that AEOD case study was published in "Operating Experience Feedback Report - Service Water System Failures and Degradations," NUREG-1275, Volume 3.

Of 980 operational events involving the service water system reported during this period, 276 were deemed to have potential generic safety significance. Of the 276 events with safety significance 58 percent involved system fouling. The fouling mechanisms included corrosion and erosion (27%), biofouling (10%), foreign material and debris intrusion (10%), sediment deposition (9%), and pipe coating failure and calcium carbonate deposition (1%).

The second most frequently observed cause of service water system degradations and failures is personnel and procedural errors (17%), followed by seismic deficiencies (10%), single failures and other design deficiencies (6%), flooding and significant failures 4% each.

During the evaluation period 12 events involved a complete loss of the service water system.

Following the evaluation of service water events, several NRC requirements were originated:

- Conduct, on a regular basis, performance testing of all heat exchangers, which are cooled by the service water system and are needed to perform a safety function. The testing performed should verify heat exchanger heat transfer capability.

- Require licensees to verify that their service water systems are not vulnerable to a single failure of an active component.

- Inspect, on a regular basis, important portions of the service water piping for corrosion, erosion, and biofouling.

- Reduce human errors in the operation, repair, and maintenance of the service water system.

4.8.3 Summary

Due to the significance of the service water system's contribution to core damage frequency in the probability risk assessment studies and the systems' troubled operating experiences, the NRC determined that compliance with 10CFR50 Appendix A, General design Criteria (GDC) is in question. Table 4.8-1 lists the service water system's contribution to core damage frequency (CDF) in terms of an absolute value and a percentage for a collection of BWRs and PWRs. The contribution made by service water to the total CDF varies from <1% to 65%. The reasons for the large differences for the most part have to do with the degree of dependency a plant has on service water, the reliability of the systems themselves, and to some extent, the differences in the PRAs in terms of modeling assumptions

Generic Letter 89-13 was issued to require licensees to supply information about their respective service water systems to assure the NRC of such compliance and to confirm that the safety functions of their systems are being met.

Table 4.8-1 Service Water Contribution to Core Damage Frequency

Plant	Type	Total Internal CDF (mean)	SW CDF Contribution	SW % Contribution
Calvert Cliffs 1	PWR	$1.3x10^{-4}$	$1.4x10^{-5}$	11
Point Beach 1	PWR	$1.4x10^{-4}$	$2.6x10^{-5}$	19
Turkey Point 3	PWR	$7.1x10^{-5}$	$3.4x10^{-6}$	5
St. Lucie 1	PWR	$1.4x10^{-5}$	$1.8x10^{-6}$	13
ANO-1	PWR	$8.8x10^{-5}$	$1.1x10^{-5}$	12
Quad Cities 1	BWR	$9.9x10^{-5}$	$3.0x10^{-5}$	30
Cooper	BWR	$2.9x10^{-4}$	$1.9x10^{-4}$	65
Surry 1	PWR	$4.0x10^{-5}$	$1.5x10^{-8}$	<1
Sequoyah 1	PWR	$5.7x10^{-5}$	$2.4x10^{-7}$	<1
Peach Bottom 2	BWR	$4.5x10^{-6}$	$1.4x10^{-6}$	22
Grand Gulf	BWR	$4.1x10^{-6}$	$5.6x10^{-7}$	14

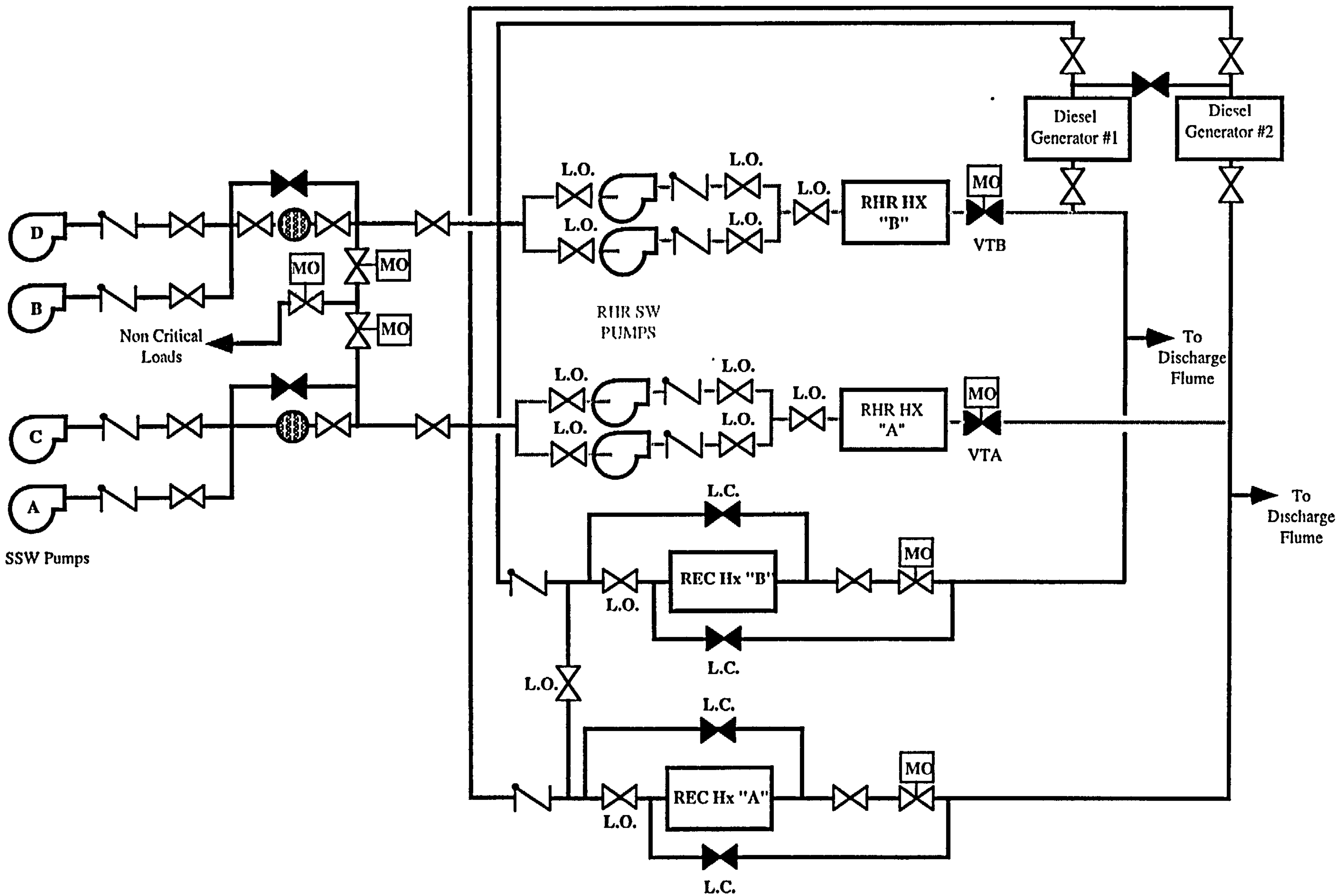

FIGURE 4.8-1 COOPER STATION

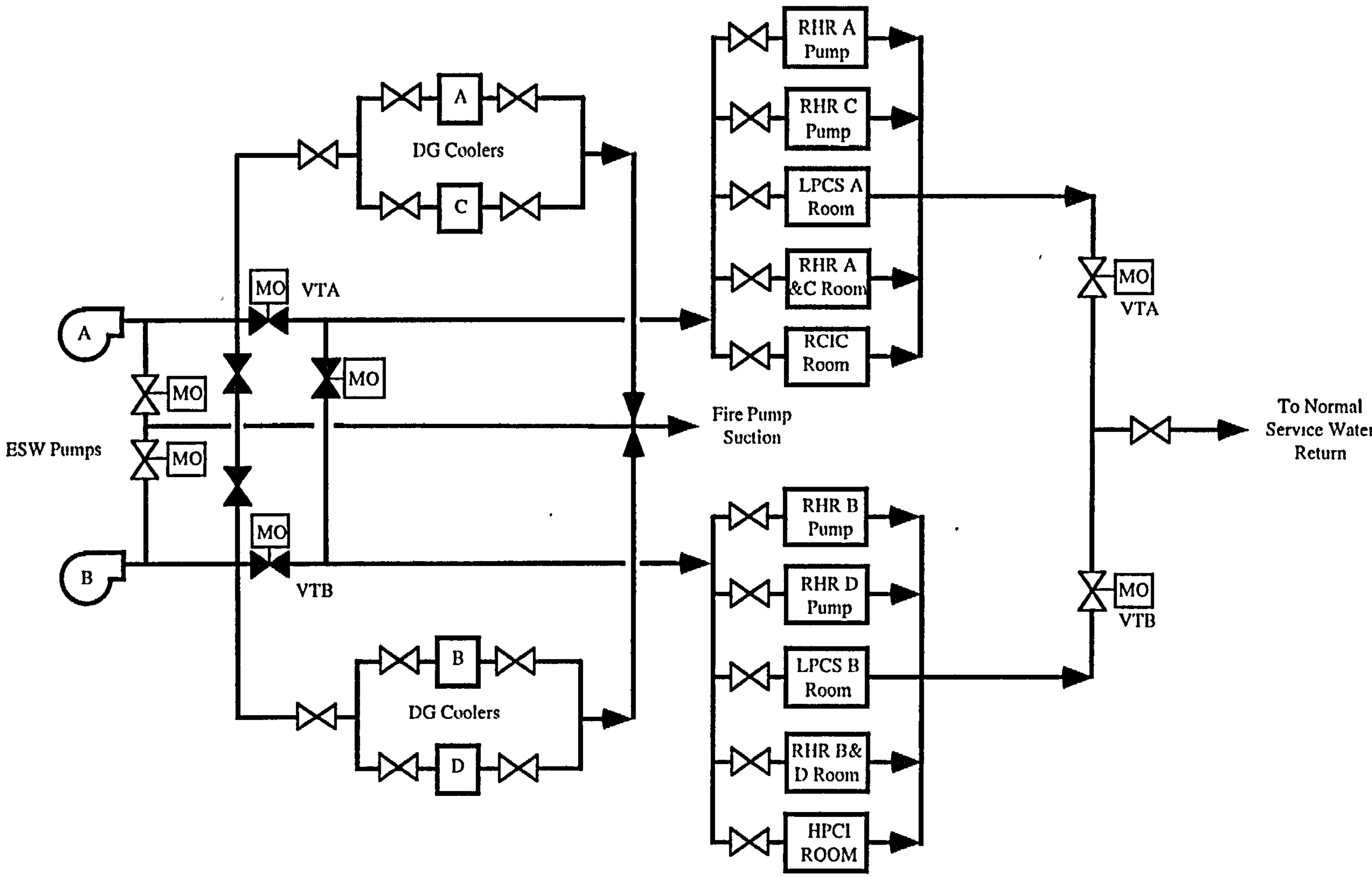

FIGURE 4.8-2 Fitzpatrick

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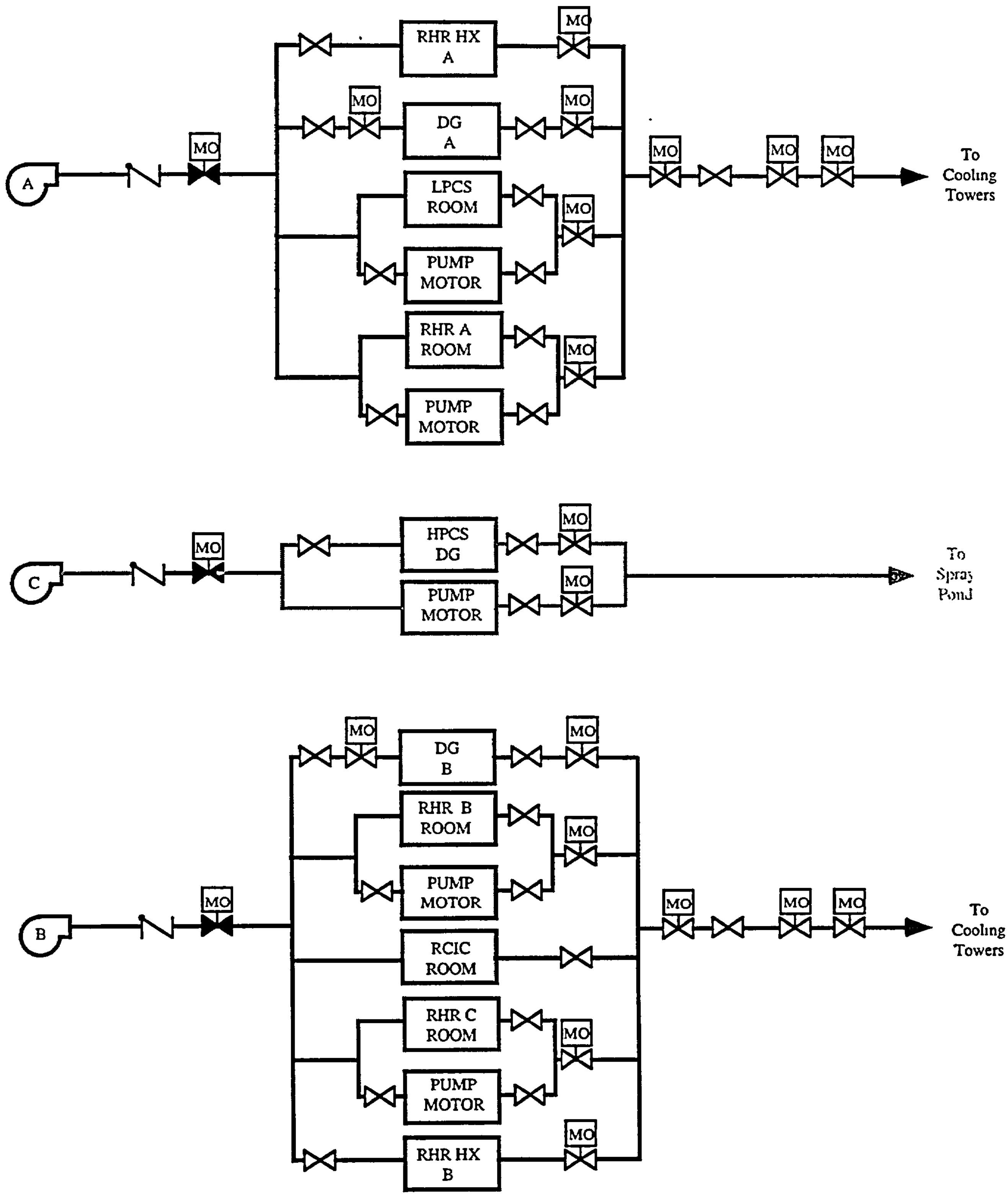

FIGURE 4.8-3 WNP-2

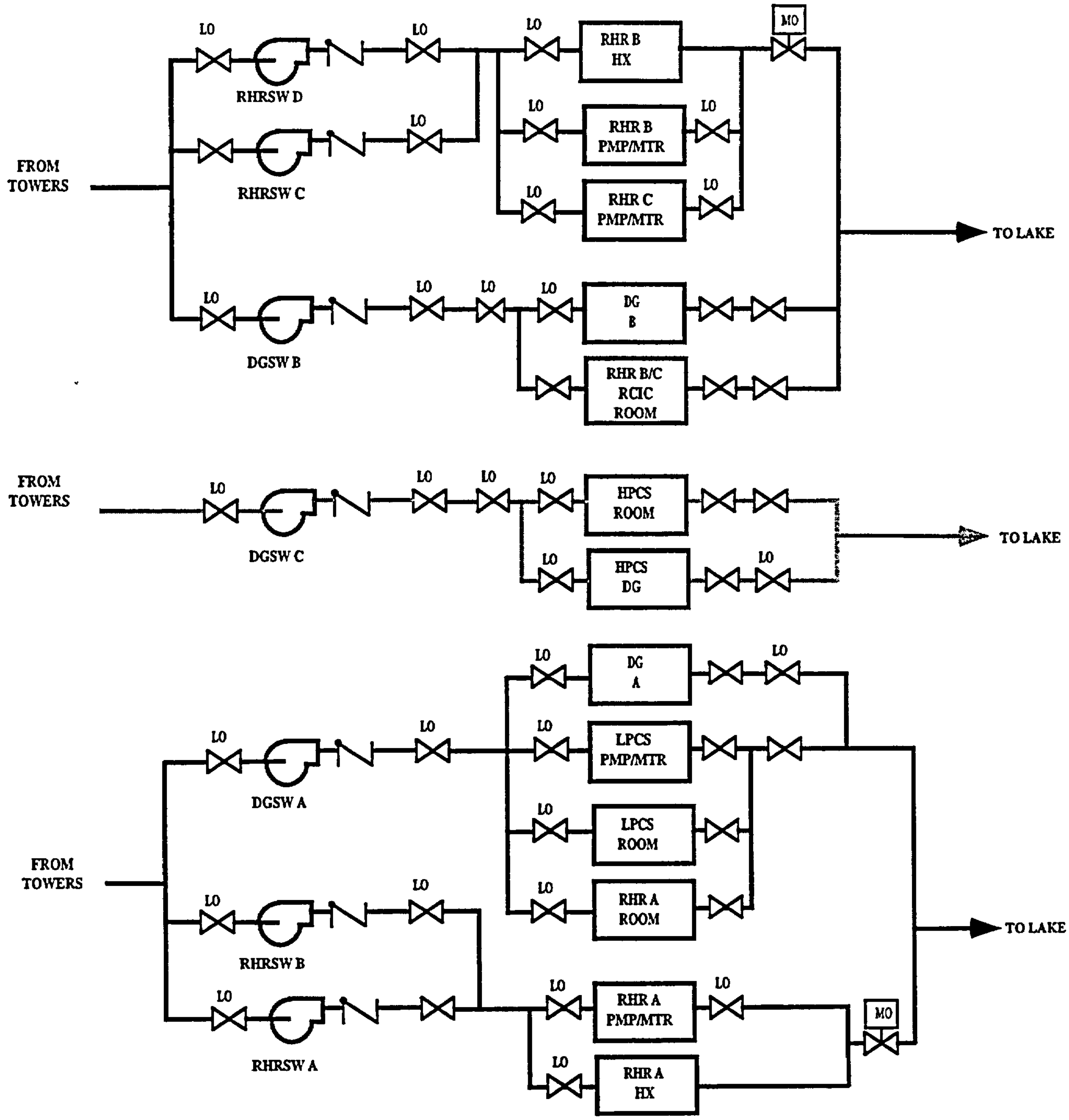

Figure 4.8-4 La Salle

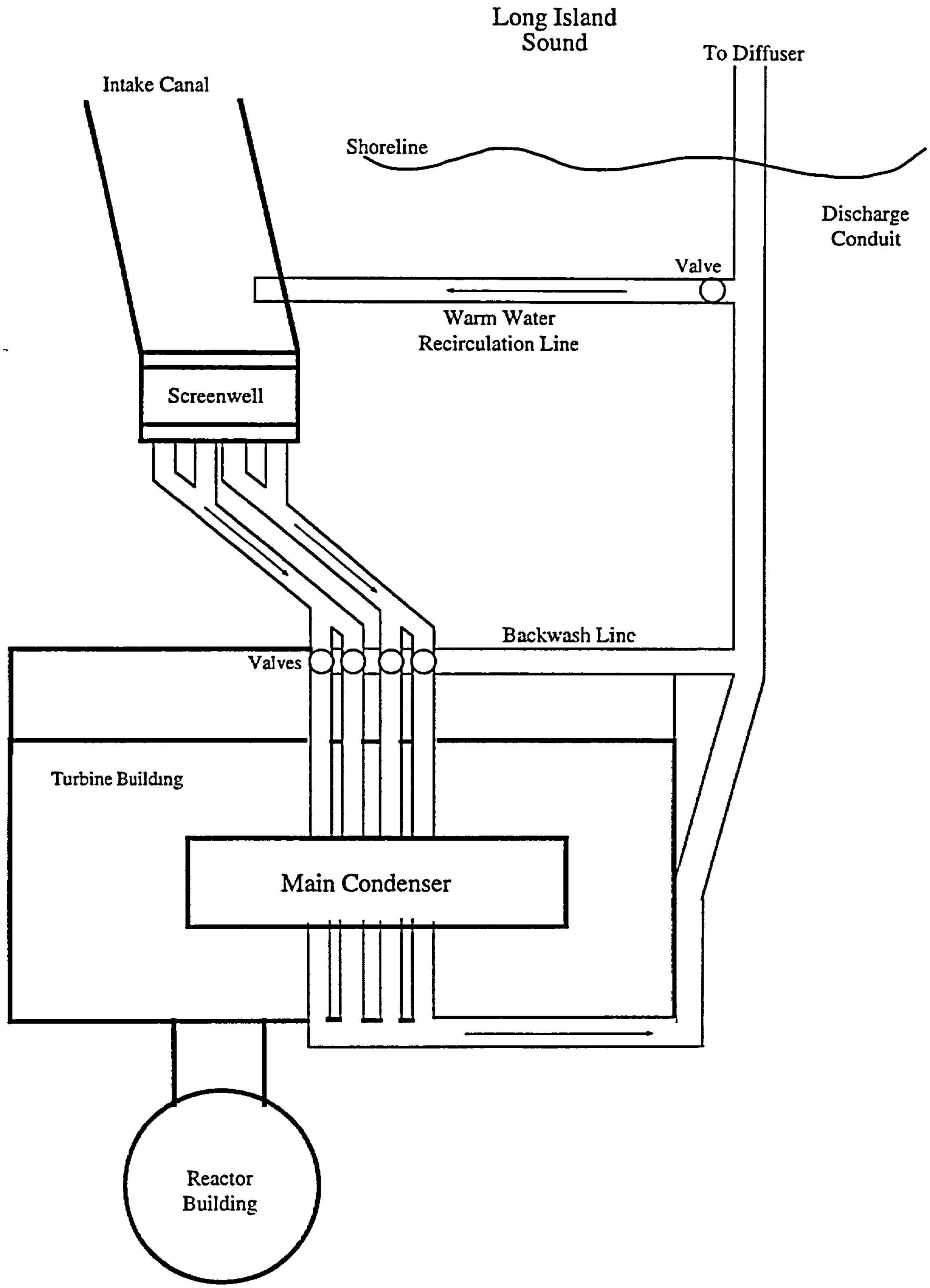

Figure 4.8-5 Circulation Water System Overview

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4.9 Stress Corrosion Cracking

Learning Objectives

1. List five reactor vessel internal components that are susceptible to IGSCC/IASCC.
2. List the purposes of the core shroud.
3. List the five factors used to establish a susceptibility ranking to shroud cracking.
4. List the three accident scenarios of primary concern associated with weld cracks in core shrouds.
5. List the three primary fixes being used to mitigate IGSCC/IASCC concerns.
6. List the two benefits of zinc injection.

4.9.1 Introduction

Corrosion is the weakening of a structural component as a result of a material deterioration caused by electrochemical reaction with the surrounding medium. The effects can be global or highly localized. Global effects are referred to as general corrosion. The localized effects usually involve some form of crack development.

Stress corrosion cracking (SCC) is a common form of highly localized corrosion phenomena. SCC can occur in ductile materials with little or no plastic strain accumulation associated with the process. The development of SCC in a structural component requires the simultaneous presence of three conditions:

- a conducive environment
- a susceptible material
- tensile stress above the threshold level

SCC is not expected to develop when any one of the three conditions is absent from the operating environment. Thus the elimination of one condition is the basis for formulating strategies to control SCC. Depending on the alloy compositions and the nature or stressors present, cracks can develop along grain boundaries. When this occurs it is called inter granular stress corrosion cracking (IGSSC).

The hot oxygenated water creates a corrosive environment in the BWR pressure vessel. The dissolved oxygen increases the electrochemical potential of type 304 stainless steel and makes it vulnerable to corrosion attacks. The presence of impurities, such as chlorides and sulfates, in the reactor coolant system may accelerate the crack development process.

In addition to the oxygenated water, the welding process can provide the other two conditions necessary for the development of SCC. When a weld is cooled down through the temperature range from 1500 to 900 °F (820 to 480 °C) type 304 stainless steel undergoes a sensitization process characterized by chromium depletion at grain boundaries. The sensitization makes austenitic stainless steels susceptible to corrosion attacks. The presence of residual stresses in weld heat affected zones supplies the third requirement for SCC. Most of the SCC failures in BWR internals are found in weld heat affected zones.

Because most BWR vessel components are made of material that are susceptible to IGSCC, the industry has attempted to establish a susceptibility ranking for each plant which considers (table 4.9-2):

- length of operation
- water chemistry/conductivity
- material susceptibility
- fabrication
- fluence

Shorter operational times, low conductivity reactor coolant water, the use of low carbon materials, minimal surface cold work, low weld residual stresses, and lower fluence levels reduce the likelihood of cracking.

4.9.2 Inspection Methods

At the present there are two methods being employed to locate cracks and to estimate their lengths. The two methods are the specialized visual inspection (VI) and ultrasonic testing (UT).

Specialized visual inspections have primarily been performed on the outside diameter (OD) weld surfaces of the shroud. Inside diameter (ID) surfaces have also been performed, although the presence of other reactor vessel internal components have limited the inspect able area or prohibited visual inspections altogether.

Ultrasonic testing examinations in some locations provide the only possible means of examination since the visual inspection accessibility of this region is blocked. One such area is the H2 weld location that is blocked by the core spray piping and spargers

4.9.3 Field Experiences

Cases of IGSSC and Irradiation Assisted Stress Corrosion Cracking (IASCC) have been reported at various BWRs. The cases range form penetrations to structural components. This section will discuss the various reactor vessel components, penetrations, and piping that are susceptible to stress corrosion cracking.

4.9.3.1 CRD Stub Tube Penetration

A few cases of IGSSC have been reported in the CRD stub tube penetration in the BWR fleet. In all cases, indications were found in furnace sensitized 304 stainless steel material. There is no history of CRD stube tube stress corrosion cracking in Alloy 600 or Allow 182 J-welds.

The CRD stub tube penetrations are Alloy 600 and are welded inside the vessel to a 304 stainless steel CRD housing by an Alloy 182 field weld (known as a J-weld). The penetration is also welded with Alloy 182 to the inside of the bottom head.

SCC is a potentially significant degradation mechanism for Alloy 182 and sensitized 304 stainless steel. Weld stress is the only significant stress for this penetration.

If the sensitized regions or the weld between the penetration and housing developed SCC, there should be no operational impact since reactor water exists on both sides of the housing. In an extreme case where the housing could be considered deformed, the ability of the housing to support the fuel and the ability of the control blade to insert could be questionable. SCC in the J-weld could also lead to leakage between the CRD housing and stub tube. There is a possibility of leakage in the large number of stub tubes, so these tubes would in turn require inspection and/or repair.

If repair is necessary due to CRD stub tube inspection, the General Electric recommended fix is to install a mechanical sleeve.

4.9.3.2 In-Core Housing

An instance of IGSCC occurred in an in-core housing at a plant located outside the United States. The plant is similar in design to a BWR/4. Reactor pressure vessel leakage was discovered at the joint where the in-core housing penetrates the bottom head. Leakage was found to be caused by a SCC thru-wall crack in the heat affected zone.

If the sensitized region above the weld developed IGSCC, leakage would occur inside the penetration. If the penetration-to-vessel Alloy 182 weld developed SCC, the crack would grow through the housing or along the weld and cause a leak. In a worst case scenario, the crack may grow into the vessel, where service-induced crack growth might cause the crack to reach a critical size where lower temperature operation such as pressure testing could initiate brittle fracture of the vessel. Margins in operating methods make this scenario unlikely, but the consequences would be severe from both a safety and economic view.

If repair is necessary for the in-core housing, GE-NE would expand the housing to make contact with the vessel bottom head material.

4.9.3.3 Recirculation Inlet and Outlet Nozzle

IGSCC has been found in recirculation inlet nozzles. The initiation of IGSCC occurs in the Alloy 182 weld butter which joins the safe ends to the nozzle attachment. A few instances have found some extensions of cracking into the stainless steel safe end nozzle material. SCC has also been observed in the 304 stainless steel thermal sleeve of a domestic BWR/3. No cracking has been observed propagating in the low alloy steel.

In a worst case scenario, the crack may grow into the vessel, where service-induced crack growth might cause the crack to reach a critical size where lower temperature operation such as pressure testing could initiate brittle fracture. Margins in operating methods make this scenario unlikely, but the consequences would be severe from both a safety and economic view.

4.9.3.4 Shroud-to-Shroud Support Weld

The shroud support consists of a horizontal Inconel plate (in four weld segments) welded on the inside of the vessel. A vertical Inconel ring is welded to the support plate which is in turn welded to the shroud. Structural support is added to the support plate by 22 Inconel gusset plates welded to horizontal plate and to the vessel wall. No field data dealing with IGSCC failures in shroud-to-vessel welds is available; due to the difficulty in accessing this area. Many plants have not completed visual examinations of this area.

If SCC initiation occurred, service-induced crack growth may cause cracks to grow into the vessel's low allow steel. Once in the allow steel, cracks could reach critical size so that the lower temperature operations like pressure testing could initiate brittle fracture. Margins in operating methods make this scenario very unlikely, but the consequences would be severe from both a safety and economic point of view.

4.9.3.5 Core Shroud

The core shroud is a stainless steel cylinder assembly, Figure 4.9-1; that surrounds the core. The shroud provides the following functions/purposes:

- A barrier to separate or divide the upward core flow from the downward annulus flow.
- A vertical and lateral support for the core plate, top guide and shroud head.

- A floodable volume in the event of a loss of coolant accident.
- A mounting surface for the core spray spargers.
- A core discharge plenum, directing the steam water mixture into the moisture separator assembly.

The core shroud is welded to and supported by the baffle plate (shroud support plate). The upper surface is machined to provide a tight fit with the mating surface of the shroud head. Mounted inside the upper portion of the shroud, in the space between the top guide and the shroud head base, are the two core spray spargers. Typical cross-sectional dimensions range from 14 feet to more than 17 feet in diameter with a wall thickness between 1.5 inches to 2 inches. Core shrouds were fabricated from 1.5 inches to 2 inches primarily for stiffness considerations for transport and installation. Boiling Water Reactor (BWR) shrouds are typically manufactured from either plate rings or forged rings of type 304 or 304L stainless steel. Fabrication of the plate portions of the shroud involves both axial and circumferential welds. Fabrication of the ring forging involves only circumferential welds. The circumferential welds in the shroud are identified according to their vertical location as shown in Figure 4.9-1, although the exact numerical notation may vary from plant to plant.

Numerous instances of shroud cracking have occurred in the BWR fleet. The first occurrence of cracking occurred in a BWR/4 located outside the United States. Cracking indications were observed in the circumferential beltline seam weld of the Type 304 stainless steel (with medium carbon content) core shroud. Circumferential crack indications with short axial components were observed in three locations on the inside surface of the shroud and were confined to the heat affected zone of the circumferential weld. Short, axial indications were also observed on the outside surface of the shroud in the same heat affected zone. Multiple UT examinations have been performed after these indications were found, with the most recent exam finding significant crack growth over a single cycle. An evaluation of cracking was performed and found that the cracking was due to IASCC.

The second instance involved cracking at a domestic GE BWR/4. Crack indications were discovered during in-vessel inspection of reactor internals. Indications of cracking were circumferentially located in the top guide support ring parallel to the plane of the ring and adjacent to the H-3 weld. Indications were also found on the outside surface of the shroud adjacent to the H-4 weld, oriented axially and measuring about on inch. Crack initiation was found to occur by IGSCC and was accelerated by IASCC contribution.

The third instance of cracking occurred in another domestic BWR/4. Indications were seen in both circumferential and axial directions at the H-3 and H-4 welds. In addition, circumferential indications were observed in the shroud plate associated with the vertical weld.

In order to assess the significance of potential cracking worse than that observed to date, the NRC has evaluated the safety implications of a postulated 360 degree circumferential separation of the shroud. The staff's evaluation determined that the detectability and consequences of 360 degree through-wall cracking are directly related to weld location at which the cracking occurs. In addition, the staff's evaluation identified three accident scenarios:

- main steam line break
- recirculation line break
- seismic events

At the upper shroud elevations (H1, H2, and H3), lifting of a separated shroud is expected to occur due to differential pressure in the core being sufficient to overcome the downward force created by the weight of only a small portion of the remaining upper shroud assembly. As such, bypass flow through the gap created by the separation is sufficient to cause a power/flow mismatch indication in the control room. The main concern associated with cracks in the upper shroud region is during a steam line break. With a main steam line failure, the lifting forces generated may elevate the top guide sufficiently to reduce the lateral support of the fuel assemblies and could prevent control rod insertion.

At the lower shroud elevations (H4, H5, ...), shroud lifting may not occur due to insufficient core pressure differential necessary to overcome the downward force from the weight of the shroud. As such, detectability of bypass flow is not assured. The main concern associated with cracks in the lower elevations of the core shroud is the postulated recirculation line break. Recirculation line break loadings, if large enough, could cause a lateral displacement or tipping of the shroud which could affect the ability to insert control rod and may result in the opening of a crack. If the leakage were large enough, it could potentially affect the ability to reflood the core and maintain adequate core cooling flooding. In addition, the ability to shut down the reactor with the Standby Liquid Control System could be reduced.

Other concerns have been raised over the potential for damage to reactor vessel internals due to shroud displacement during postulated accident conditions. In particular, the possibility may exist for damage to the shroud support legs due to impact loading from the settling of the shroud after a vertical displacement. In addition, displacement of the shroud could cause damage to core spray lines.

The NRC developed a probabilistic safety assessment regarding shroud separation at the lower elevation for two plants, Dresden Unit 3 and Quad Cities Unit 1. The staff made conservative estimates of the risk contribution from the shroud cracking and concluded that it does not pose a high degree of risk at this time. However, the staff considers a 360 degree cracking of the shroud to be a safety concern for the long term based on:

- Potentially exceeding the ASME Code structure margins if the cracks are sufficiently deep and continue to propagate through the subsequent operating cycle.
- The uncertainties associated with the behavior of a 360 degree through-wall core shroud crack under accident conditions.
- The elimination of a layer of defense-in-depth for plant safety.

4.9.3.6 Access Hole Cover

The access cover is a 2 inch thick Alloy 600 cover welded to the 2 ½ inch thick shroud support. Extensive cracking has been found in several access hole covers in the BWR fleet. Cracking has occurred in creviced Alloy 600 covers welded with Alloy 182 weld metal and has initiated in the heat affected zone of the cover plate. Intermittent circumferential cracking has been the most common orientation of cracking.

In the worst case, access hole cover cracking could progress through wall and cause the cover to detach either partially or completely. A substantial flow path from the bottom head into the annulus region would be created, impacting core flow distribution during normal operation. The distribution would be detectable at significant levels. Such cracking would impact the boundary which assures 2/3 core coverage following a LOCA event. The consequence of cracking is high.

General Electric has replaced approximately 20 access hole covers to date. With a cost of approximately $6 million per plant.

4.9.3.7 Jet Pump Riser Brace

The jet pump riser brace is connected to the riser pipe by a single bevel weld. At least one occurrence of IGSCC has been documented by General Electric. During visual examination at a BWR/4, a crack was found on the weld that attaches the riser brace yoke to the jet pump riser pipe. Cracking extended out of the heat affected zone of the weld and into the riser pipe. Although no definitive answer was reached, it is believed that the cracking initiated by an IGSCC mechanism and propagated by high cycle fatigue.

At the crack location between the brace and the riser, a crack could have significant consequence on operation and safety. The brace is intended to provide structural support at the upper part of the jet pump assembly and lateral support to maintain jet pump alignment.

4.9.3.8 Piping Cracks

Piping cracks from IGSCC was identified as early as 1965. In December of 1965, during a hydrostatic pressure test, a leak was observed in a 6 inch bypass line of the recirculation loop at Dresden Unit 1. Like the vessel penetrations and internals the cracks were found in the heat affected zone of welds in type 304 stainless steel. Table 4.9-3 lists the IGSCC incidents by line type in U.S. and Foreign BWRs. The data listed in the table is only good through January of 1979. Many of the cracks found after 1975 were due to the augmented inspections performed.

Following the discovery of cracks in recirculation piping, many utilities have replaced the 304 or 316 stainless steel with 316NG or 316 low carbon steel piping. This data is listed in Table 4.9-4.

4.9.4 Activities

BWR executives formed the BWR Vessel and Internals Project (BWRVIP) in June of 1994. One of the BWRVIP's first challenges was to address integrity issues arising from service-related degradation of key components, beginning with core shroud cracking. BWRVIP also implemented a proactive program to develop products and solutions that bear on inspection, assessment, mitigation, and repair.

Through BWRVIP, utilities are developing, sharing, and implementing cost-effective strategies and products for resolving vessel and internals integrity and operability problems. BWRVIP also provides the regulatory interface on generic BWR vessel and internals matters. During the first year of BWRVIP activities, the following products were developed for the core shroud: Inspection and Flaw Guidelines, NDE Uncertainty and Procedure Standard, and

Repair Design Criteria.

4.9.4.1 Hatch Fix

The design of the Hatch Unit 1 core shroud modification consists of four stabilizer assemblies, which are installed 90 degrees apart. Each stabilizer assembly consists of a upper bracket, tie rod, upper spring, lower spring, lower bracket, intermediate support, and other minor components. The tie rods serve to provide an alternative vertical load path from the upper section to the tie rod assembly through the shroud support plate gusset attachments. These tie rod assemblies maintain the alignment of the core shroud to the reactor vessel. At the top guide elevation, the upper springs are designed to provide a radial load path from the shroud to the RPV. The lower springs are designed to provide a similar radial load path (from the shroud to RPV) at the core support plate elevation. The upper bracket is designed to provide attachment to the top of the shroud, and to restrain the upper shroud weld (weld H1). The middle support for the tie rods is designed to limit the radial movement of the tie rods. Wedges placed between the core shroud plate and the shroud prevent relative motion of the core plate with the shroud.

The stabilizer assemblies are designed to prevent unacceptable lateral or vertical motion of the shroud shell sections, assuming failure (360 degrees through wall) of one or more of the structural circumferential shroud welds. The functions of the components are as follows:

- upper brackets are designed to restrain lateral movement of the shell between welds H1 and H2, and the shell between welds H3 and H4
- the limit stops located at the middle of the tie rods are designed to restrain lateral movement of the shell between welds H4 and H5
- the lower springs contact the shroud, and are designed to restrain the shell segments between welds H5 and H6a, H6a and H6b, and welds H6b and H7
- the gussets, which were originally included as part of the shroud support design, are designed to preclude unacceptable motion of the shroud between welds H7 and H8

Materials for the stabilizer assemblies was selected to provide protection for the life of the plant. In addition, the material has a different coefficient of expansion than the core shroud and causes a compressive load when at normal temperature and pressure.

4.9.4.2 Hydrogen/Zinc Injection

Protection against IGSCC deals mainly with some form of primary water chemistry control process. Hot oxygenated water creates a corrosive environment in the BWR pressure vessel. Dissolved oxygen in water increases the electrochemical potential of type 304 stainless steel and makes them vulnerable to corrosion attacks. By controlling the environment surrounding the reactor vessel internals, IGSCC can be mitigated.

Hydrogen Addition

The purpose of hydrogen water chemistry control is to suppress oxygen in the reactor water. By suppression the oxygen level in reactor water:

- General corrosion is controlled
- Characteristics of corrosion film layer in recirculation piping and reactor vessels are changed

- A reduction in the oxidation state of chromium is realized.

In response to the unacceptable degradation of reactor vessel components from Intergranular Stress Corrosion Cracking (IGSCC) a number of BWRs have adopted hydrogen water chemistry. Hydrogen water chemistry implies a low dissolved oxygen content coupled with low conductivity.

Hydrogen water chemistry appears to improve the margin for stress corrosion and corrosion fatigue of carbon and low alloy steels, but has a slight adverse affect on their overall corrosion kinetics.

Under hydrogen water chemistry, the dissolved oxygen in the recirculation systems decreases below the acceptable value for minimal corrosion of carbon steel piping. At very low levels of dissolved oxygen the protective corrosion film on carbon steel undergoes dissolution and produces accelerated corrosion of the base metal. Therefore, sufficient oxygen is added to the condensate system to maintain oxygen between 20 and 50 ppb.

Hydrogen water chemistry provides a reducing environment that not only lowers the oxidation potential of reactor water, but also favors formation of spinel. Spinel is a thinner, more adherent film, of a complex metal matrix consisting of iron, chromium, nickel, cobalt, manganese, copper and zinc.

Historically, the corrosion films on BWR components are a combination of hematite and spinel oxides. Higher fractions of hematite in the corrosion film lead to thicker and less protective oxides. This type of corrosion film tends to increase radiation buildup by permitting more corrosion products to enter solution. This tendency is counter balanced because hematite does not have a natural site for crystal formation by divalent ions, such as cobalt. Hematite has a lower cobalt concentration than corrosion films dominated by spinel structure. This means that the radioactive material buildup is not controlled solely by oxide layer thickness.

BWR chemistry without hydrogen water control provides oxidizing conditions in the reactor coolant. Under oxidizing conditions, stable oxygen-16 is activated to nitrogen-16 by a neutron-proton reaction. The resulting nitrogen-16 is primarily in the form of soluble nitrates (NO_3) and nitrites (NO_2) with a small amount in the form of volatile ammonia (NH_4).

Hydrogen water chemistry changes the BWR coolant to a reducing environment. Under reducing conditions, the chemical equilibrium shifts from nitrate/nitrite in favor of volatile ammonia. Nitrogen-16 carryover into the main steam system then increases by as much as a factor of five at full power. The carryover of nitrogen-16 results in significant increased dose rates in the turbine building during plant operation from 6.1 and 7.1 Mev gamma photons produced during radioactive decay. During outages, the dose rate from nitrogen-16 is not a factor since it is no longer being produced and it has a very short half-life of only 7.1 seconds.

Zinc Injection

The presence of zinc in the reactor coolant increase the spinel fraction in oxide formations on stainless steels. Spinel is a thinner (by a factor of six or more) more protective film oxide than hematite (Fe_2O_3). The corrosion protection provided by spinel based film is greater than that formed by divalent cations commonly found in BWRs. Zinc competes with cobalt for available crystal lattice sites in the spinel and under hydrogen water chemistry is the dominate divalent ion in the crystal matrix of Spinel; thereby, allowing little cobalt-60 buildup. It is hypothesized that the excess of zinc ions in a mixed metal oxide migrate to the vacant defect sites and block ion migration by other ions. This produces a quasi-stoichiometric oxide that is highly protective to the base metal.

Reducing the soluble cobalt-58 and cobalt-60 in the in the reactor coolant is an additional benefit. By reducing the long lived radioactive material that contribute to personnel exposure, BWRs see a positive impact in ALARA space.

4.9.4.3 Noble Metals Injection

Noble metals, platinum and rhodium, injection has proven that it works. The catalytic deposited layer provides the desired electrochemical corrosion potential levels for many components at a very low hydrogen injection level and extends hydrogen water control benefits to additional vessel internals. With the use of noble metals injection, approximately one-fifth of the hydrogen injection values used in traditional hydrogen injection are needed.

Noble Metals Deposition Process

The general process adds a platinum and rhodium noble metal compound to the reactor water until the concentration is 40-100 ppb platinum and 20 - 150 ppb rhodium. Injection of the noble metal solution is into the Recircualtion Loop A discharge line and the B RHR system downstream of the heat exchanger through existing small bore piping connections. The RHR system takes suction from the recirculation loop B and is returned to the same loop. Consequently, the RHR system will provide the drive flow for the B loop jet pumps. Recirculation pump A will be in operation to provide drive flow to the other jet pumps. The to flows are balanced as equal as possible to assure distribution of the noble metals compound to each loop and circulate water in the vessel.

The process is normally applied during the normal cooldown sequence prior to refueling outage. The vessel water temperature at which the process will be applied is $265^0F \pm 25^0F$. The process requires the vessel water temperature to maintained for 48 hours. Decay heat will be used to maintain the water temperature at the desired process temperature. Excess heat is remove by operating the RHR system in the shutdown cooling mode. To prevent excessive deposition on the hotter fuel clad surfaces during treatment, the fuel cladding temperature needs to be within 20^0F of the bulk coolant temperature prior to starting the process.

Surfaces that come into contact with the reactor water during the process will have a target minimum loading of 1 microgram per square centimeter for platinum and 1/3 microgram per centimeter of rhodium with a maximum of 50 and 17 respectively. Surface samples of specimens tested in autoclaves have shown that the noble metal atoms present on the surface do not completely cover the surface but are distributed randomly across the surface. Consequently, the surface is not plated and the Pt/Rh layer is discontinuous. Based on General Electric laboratory data, if gaps larger than 0.1-1 mm in the noble metal coverage exist, they will not be protected locally. If cracks develop in these regions, the lower electrical chemical protection of the adjacent noble metal regions will arrest the cracks after a microscopic amount of crack growth.

Noble Metal Effects on Large Cracks

General Electric has studied the behavior of stress corrosion cracks ranging in size from 20 micrometers to 40,000 micrometers and found that a mature crack is established in cracks less than 20 micrometers deep. There is widespread agreement that what produces the mature crack and usually aggressive crack chemistry is the difference in corrosion potential between the crack/crevice mouth and crack/crevice interior, known as a differential aeration cell. Numerous studies have shown that essentially the entire potential gradient occurs very near the crack mouth-perhaps in the first 5%of the crack crevice. If this potential gradient is substantially eliminated by excellent hydrogen water chemistry or noble metals injection, then it makes no difference how long the crack/crevice is since the driving force that produces an aggressive crack chemistry is no longer present. These same characteristics have also been shown to exist under high flux irradiation conditions.

Platinum and Rhodium serve as sites for recombination of hydrogen and oxidants. The noble metal surfaces are chemically benign in the BWR environment and have little to no effect on the water concentration of hydrogen and oxygen.

Impact on Plant Operation

During normal operation, the noble metal on the surface will prevent and mitigate stress corrosion cracking by reducing the oxidant concentration near the metal surface. The catalytic behavior of noble metals provides an opportunity to efficiently achieve a dramatic reduction in corrosion potential and stress corrosion cracking by catalytically reacting all oxidants that contact the catalytic surface with hydrogen. With stoichiometric excess hydrogen, corrosion potential decreases dramatically and crack initiation and growth are greatly reduced, even at high oxygen and hydrogen peroxide levels. Low hydrogen addition rates are necessary to provide sufficient hydrogen at the surface of noble metal treated components. Oxygen that diffuses to the component surface will immediately react with the excess hydrogen to form water. In this way the boundary layer of all noble metal wetted components is depleted of oxygen and maintains a very low corrosion potential. Noble metal utilizes veyr reactive surfaces to maintain oxygen deficient water in contact with reactor components. Moderate to high hydrogen water chemistry control, on the other hand, are brute force methods to reduce the oxygen content of the entire bulk coolant to be effective and increase the main steam line radiation levels.

Table 4.9-1 Shroud Cracking Experiences

Plant	Date of Operation	Summary
Brunswick 1	03/18/77	360° circumferential crack at H3 weld in the top guide support ring, 0.8" to 1.7" deep. Less significant circ. and axial cracks at H1 to H6. The H2 and H3 welds were repaired with 12 through-bolt clamps.
Brunswick 2	11/3/75	Significant cracking was observed during visual inspection (VI).
Dresden 3	11/16/71	The H1 through H7 welds have been inspected. 360° cracking on OD at weld H5, significant cracking indicated on the ID at weld H3. Safety evaluation (issued July 20, 1994) has allowed operation for no more than 15 months.
Duane Arnold	02/1/75	An ID examination was performed in accordance with the recommendations of GE SIL, discovering no indications of cracks. The plant has an L-grade shroud and uses hydrogen water control.
Fermi 2	01/23/88	Minor axial indications were discovered at H2 weld.
Hatch 1	12/31/75	The licensee installed a preemptive shroud repair in lieu of inspection and potential evaluation of identified flaws.
Hope Creek	12/20/86	A limited examination has been performed with the discovery of no cracks. The plant has L-grade shroud.
Millstone	03/01/94	Minor circumferential cracks present at H3, H4, and H5 weld locations. No repair has been implemented.
Monticello	06/30/71	Licensee completed a UT and enhanced VI of accessible welds. Minor indications observed at H2, H3, and H4
Nine Mile Pt. 2	03/11/88	Shroud is fabricated from low carbon stainless steel. Plant is outside the scope of GE SIL recommendations.
Oyster Creek	12/1/69	Licensee completed inspection in 1994 refueling outage. Minor circumferential indications on H2, H6a, and H6b welds. Extensive cracking on OD and ID of H4. Licensee is installing shroud repair.

Table 4.9-2
BWRVIP Susceptibility Rankings and Core Shroud Inspection Recommendations

Category	Inspection Recommendations	Plant Characteristics	Plants
A	No inspection necessary at this time.	Plants with 304 SS shrouds, <6 years hot operating time, and avg. conductivities ≤0.030uS/cm (0.030umhos/cm) during the first five cycles of operation.	None
		Plants with 304L SS shrouds,<8 years hot operating time. and avg. conductivities ≤0.030uS/cm (0.030 umhos/cm) during the first five cycles of operation	Clinton, Fermi 2, Perry, Hope Creek, Limerick 2, Nine Mile Pt .2. Washington Nuclear Plant 2. River Bend
B	Limited inspection: top guide support ring, core support ring, and mid shroud shell circumferential welds; also the bimetallic weld if accessible.	Plants with 304L SS shrouds, ≥8 years hot operating time, and avg. conductivities ≤0.030uS/cm (0.030 umhos/cm) during the first five cycles of operation	Grand Gulf, LaSalle 1 & 2 Limerick 1, Susquehanna 1 & 2
C	Comprehensive inspection: Circumferential shroud welds H1-H7 (and H8 for BWR-2s)	Plants with 304SS shrouds and ≥ 6 years hot operating time, regardless of conductivity.	Shrouds-weld, plate rings Bruinswick 1& 2, Dresden 2 & 3, FitzPatrick, Hatch 1, Millstone 1, Oyster Creek, Nine Mile Point 1, Pilgrim Quad Cities 1 & 2 Shrouds- Forged rings Browns Ferry 1, 2 & 3, Peach Bottom 2 & 3, Vermont Yankee, Monticello, Cooper
		Plants with 304L SS shrouds. >8 years hot operating time. and avg. conductivities >0.030uS/cm (0.030 umhos/cm) during the first five cycles of operation	Duane Arnold. Hatch 2

Table 4.9-3 IGSCC Incidents by Line Type in U.S. and Foreign BWR's[a]

	Number IGSCC Incidents		
System Component (pipe diameter)	Before July 1975	July 1975 to January 1979	Totals
Recirculation Bypass Line (4-inch)	30	12	42
Core Spray Pipe (10-inch)	16	17	33
Control Rod Drive System Small Bore Pipe (CRD, 3-inch)	1	1	2
Reactor Water Cleanup (RWCU; 3- to 8-inch)	10	14	24
Large Recirculation (≥ 12-inch)	0	13	13
Small Bore Pipe (≥ 3-inch) other than CRD and RWCU	0	6	6

Notes: (a) Cracking incidents reported to NRC

Table 4.9-4 Status of U.S. BWR Piping

Plant		Date of Operating License	Original Design Material	Replacements for Recirculation Piping	Replacements for RHR Piping[b]	Hydrogen Water Chemistry Implemented?
Design	Name					
BWR/2	Nine Mile Point 1	12/26/74	304SS or 316SS	Full, 316SS (low carbon)	Full, 316SS (low carbon)	Yes
	Oyster Creek	08/01/69	304SS or 316SS	None	None	Yes
BWR/3	Dresden 2	02/21/70	304SS or 316SS	None	None	Yes
	Dresden 3	03/02/70	304SS or 316SS	Full, 316NG	Full, 316NG	No
	Millstone 1	10/31/86	304SS or 316SS	None	None	Yes
	Monticello	01/09/81	304SS or 316SS	Full, 316NG	Full, 316NG	Yes
	Pilgrim	09/15/72	304SS or 316SS	Full, 316NG	Full, 316NG	Yes
	Quad Cities 1	12/14/72	304SS or 316SS	None	None	Yes
	Quad Cities 2	12/14/72	304SS or 316SS	None	None	Yes
BWR/4	Browns Ferry 1	12/20/73	304SS or 316SS	None	None	No
	Browns Ferry 2	08/02/74	304SS or 316SS	Part[a] (riser) 316NG	None	No
	Browns Ferry 3	08/18/76	304SS or 316SS	None	None	No
	Brunswick 1	11/12/76	304SS or 316SS	Part[a] (riser) 316NG	None	Yes
	Brunswick 2	12/27/74	304SS or 316SS	Part[a] (riser) 316NG	None	Yes

Table 4.9-4 Status of U.S. BWR Piping (cont.)

Plant		Date of Operating License	Original Design Material	Replacements for Recirculation Piping	Replacements for RHR Piping[b]	Hydrogen Water Chemistry Implemented?
Design	Name					
BWR/4	Cooper	01/18/74	304SS or 316SS	Full, 316NG	Full, 316NG	Yes
	Duane Arnold	02/20/74	304SS or 316SS	None	None	Yes
	Fermi 2	07/15/85	304SS or 316SS	None	None	Yes
	FitzPatrick	10/17/74	304SS or 316SS	None	None	Yes
	Hatch 1	10/13/74	304SS or 316SS	None	None	Yes
	Hatch 2	06/13/78	304SS or 316SS	Full, 316NG	Full, 316NG	Yes
	Hope Creek	07/25/86	316NG REC, RHR RWCU	N/A	N/A	Yes
	Limerick 1	08/08/85	316NG REC, RHR, Core Spray RWCU	N/A	N/A	Yes
	Limerick 2	08/25/89	316NG REC, RHR, Core Spray RWCU	N/A	N/A	Yes
	Peach Bottom 2	12/14/73	304SS or 316SS	Full, 316NG	Full, 316NG	Yes
	Peach Bottom 3	07/02/74	304SS or 316SS	Full, 316NG	Full, 316NG	Yes
	Susquehanna Unit 1	11/12/82	304SS or 316SS	None	None	Yes
	Susquehanna Unit 2	06/27/84	304SS or 316SS	None	None	No
	Vermont Yankee	02/28/73	304SS or 316SS	Full, 316NG	Full, 316NG	No

Table 4.9-4 Status of U.S. BWR Piping (cont.)

Plant		Date of Operating License	Original Design Material	Replacements for Recirculation Piping	Replacements for RHR Piping[(b)]	Hydrogen Water Chemistry Implemented?
Design	Name					
BWR/5	La Salle 1	08/13/82	304SS or 316SSL[(c)]	None	None	Yes
	La Salle 2	03/23/84	304SS or 316SSL[(c)]	None	None	Yes
	Nine Mile Point 2	07/02/87	316NG for All Piping Systems	N/A	N/A	No
	WNP 2	04/13/84	304SS or 316SS	None	None	No
BWR/6	Clinton 1	04/17/87	316NG for REC, RWCU	N/A	None	No
	Grand Gulf 1	11/01/84	304SS or 316SS	None	None	Yes
	Perry 1	11/13/86	304SS or 316SS	None	None	No
	River Bend 1	11/20/85	316NG for REC	N/A	None	No

Notes:

(a) Recirculation system riser piping only.
(b) Residual Heat Removal piping inside containment that is classified as ASME Code Class 1 pipe.
(c) 12 inch inlet safe-ends

Abbreviation Descriptions:
Full - full replacement of the piping
Part - partial replacement of the piping
304SS - Type 304 austenitic stainless steel
316SS - Type 316 austenitic stainless steel
316NG - Type 316 austenitic stainless steel, nuclear grade quality
None - no replacement of the piping performed to date
N/A - initial material of the piping is already Type 316NG steel; replacement is not applicable in this case
REC - Recirculation System Piping
RWCU - Reactor Water Cleanup System Piping
RHR - Residual Heat Removal System Piping

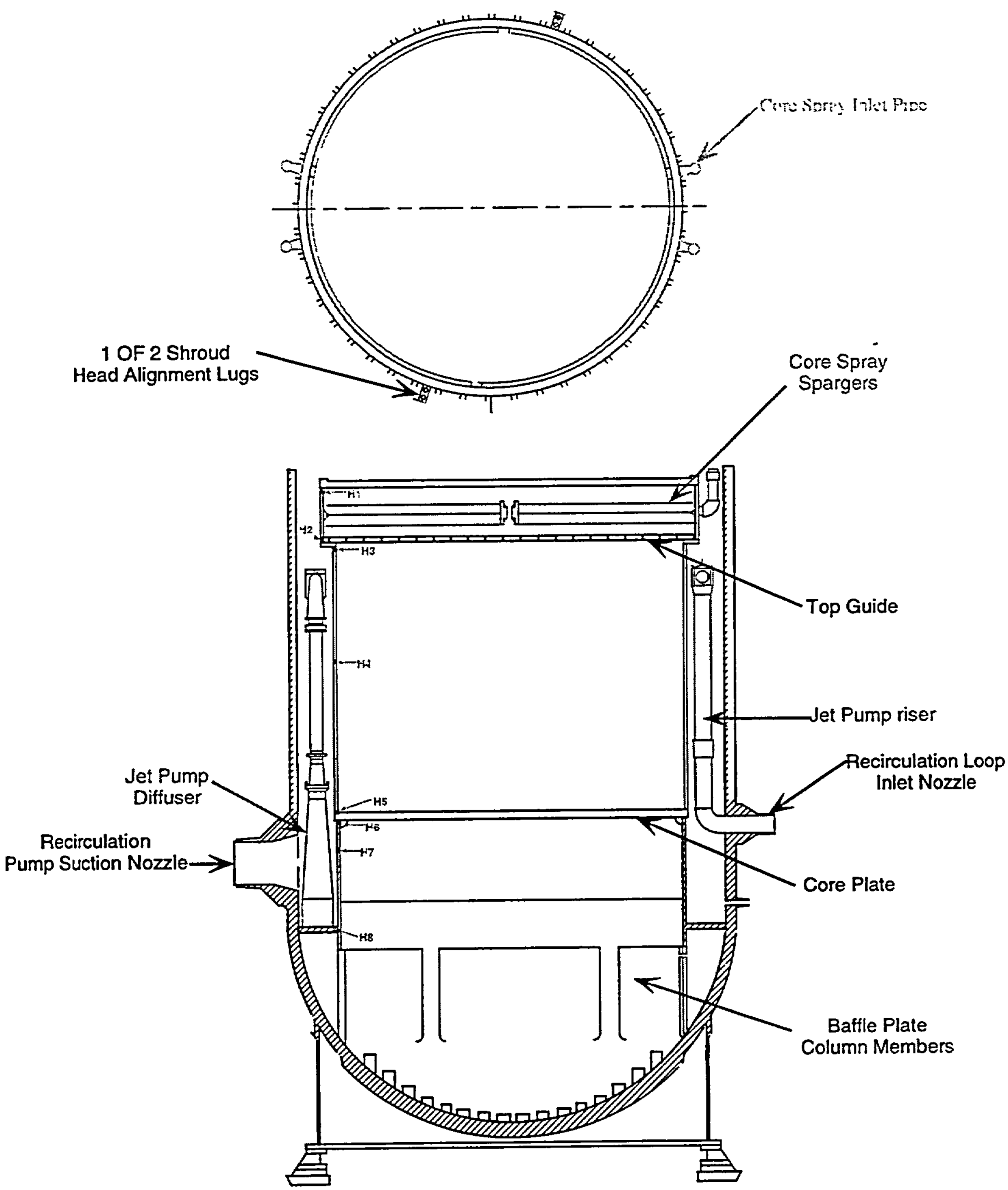

Figure 4.9-1 Core Shroud

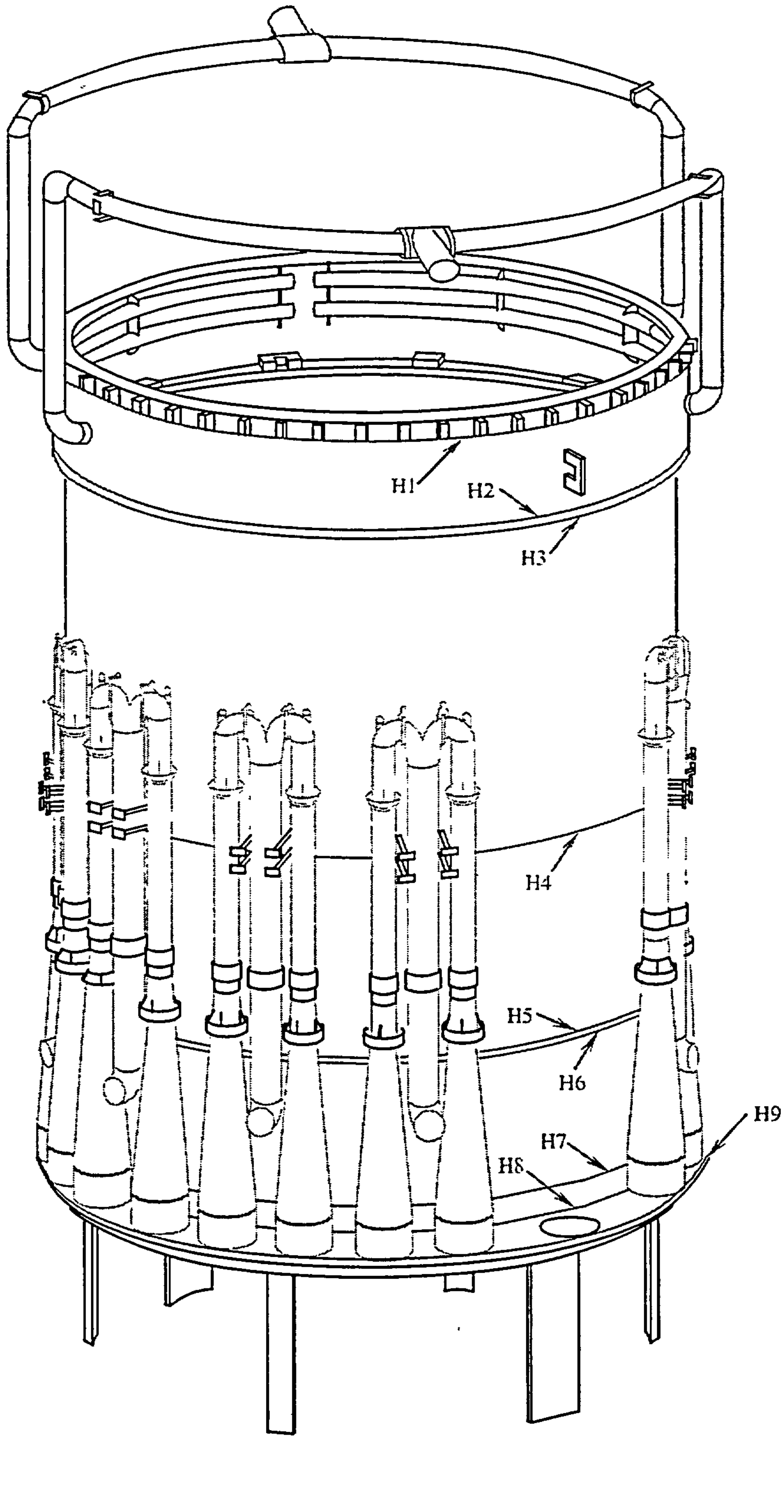

Figure 4.9-2 Core Shroud Weld Location

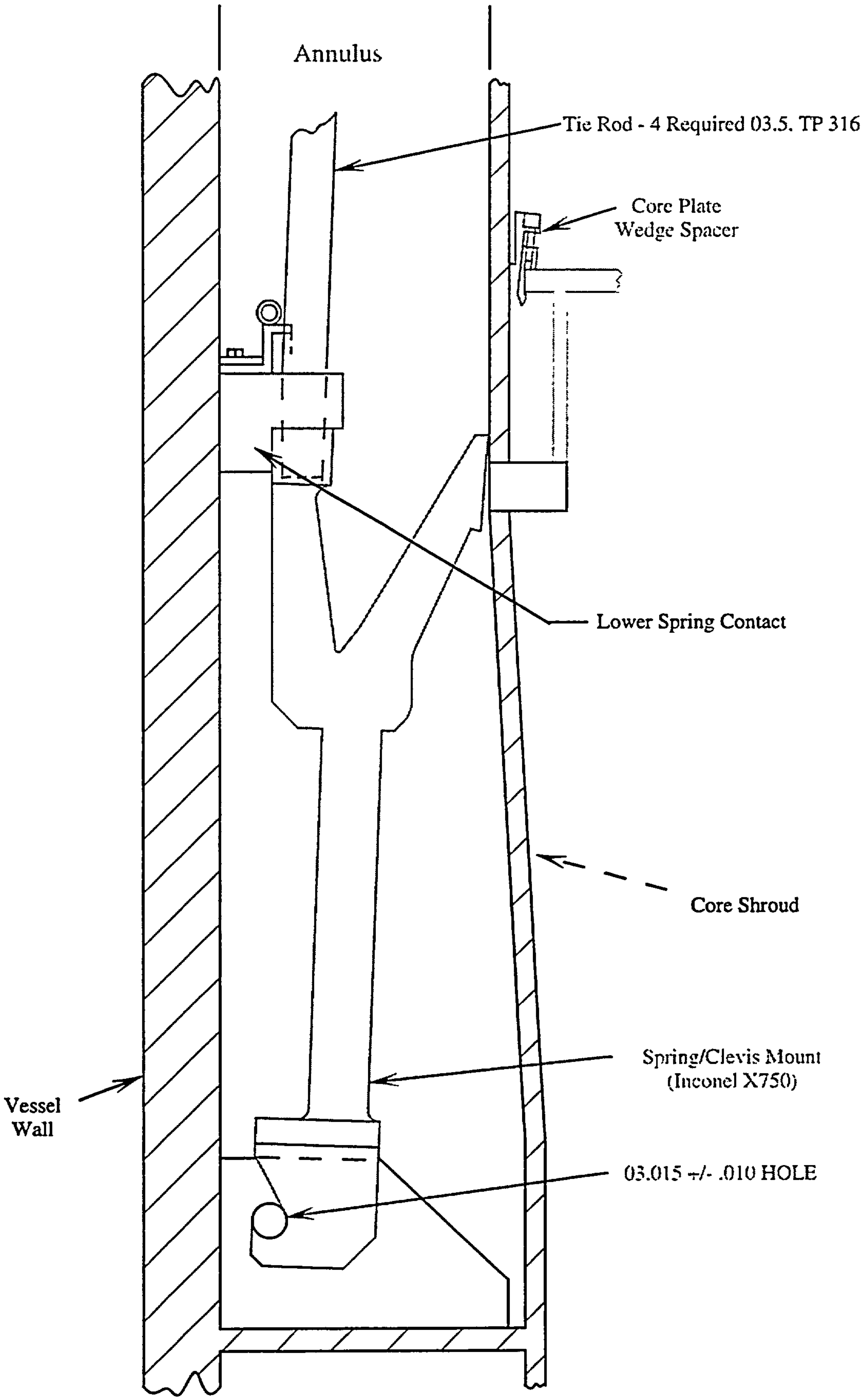

Figure 4.9-3 Lower Shroud Clamp

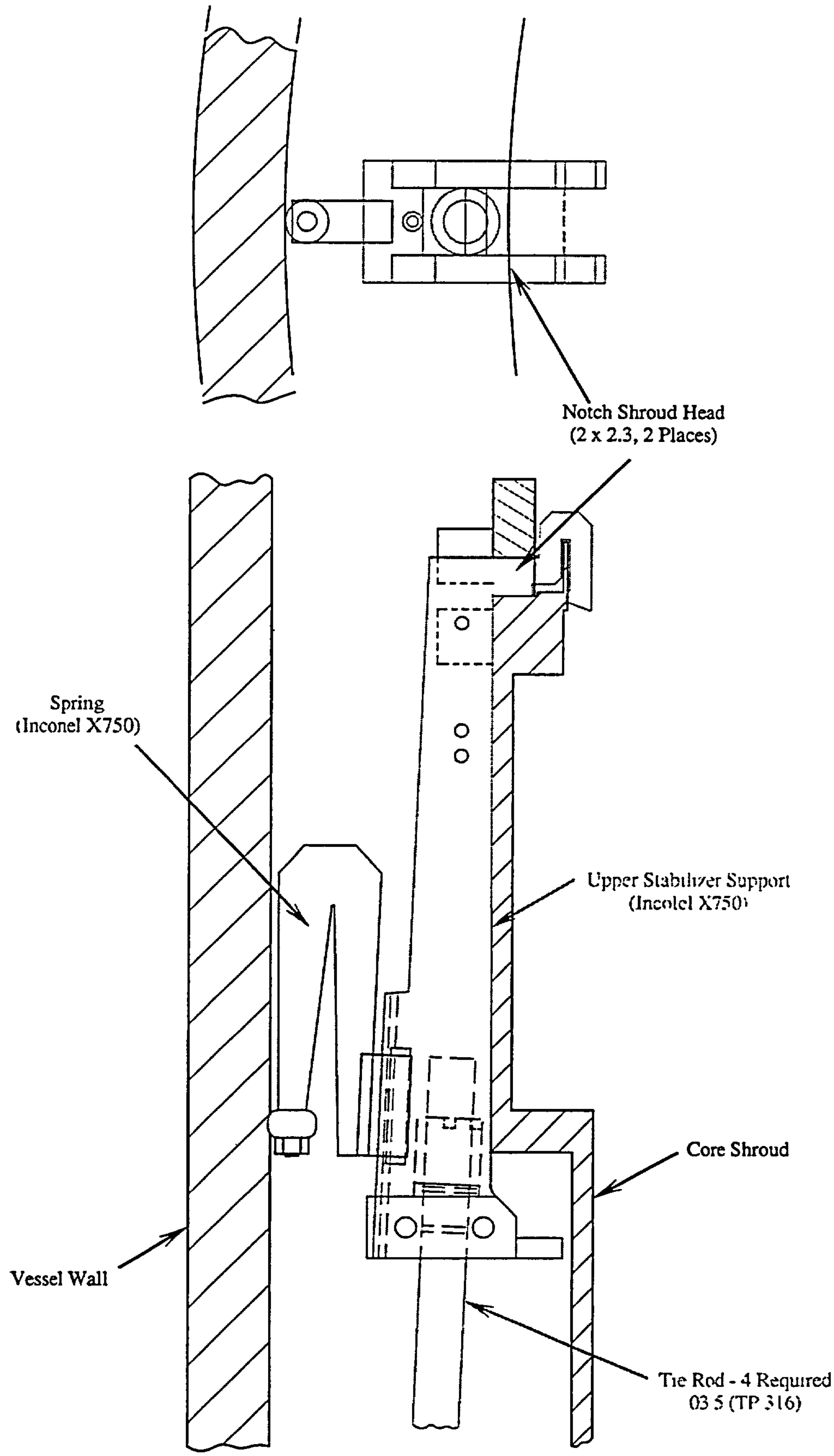

Figure 4.9-4 Upper Shroud Clamp

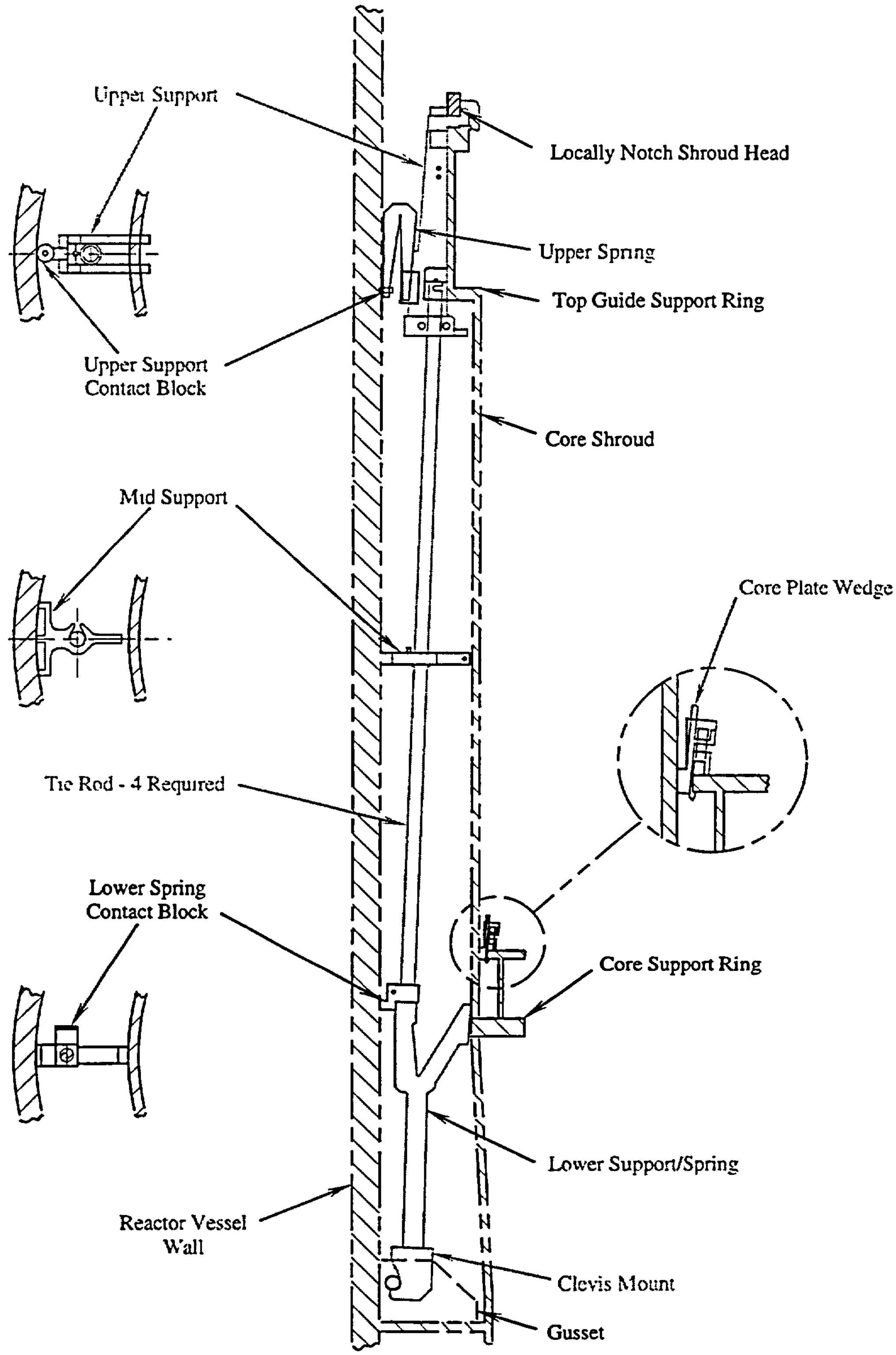

Figure 4.9-5 Shroud Clamp